CANADIAN
NATURAL GAS

Supply & Requirements

NATIONAL ENERGY BOARD
April 75

"The Board may hold a public hearing in respect of any other matter if it considers it advisable to do so".

*National Energy Board Act,
Part I, Subsection 20(3)*

"The Board may of its own motion inquire into, hear and determine any matter or thing that under this Act it may inquire into, hear and determine".

*National Energy Board Act,
Part I, Subsection 14(2)*

"In the Matter of an enquiry, hearing and determination of the reserves, requirements and deliverability of Canadian Natural Gas in relation to reasonably foreseeable requirements for use in Canada and potential for export".

*National Energy Board Hearing
Order GHR-1-74, dated
20 September, 1974.*

ERRATA

1. Page 3, Figure 1 - In title of figure, change "1973-1983" to "1973-1995".

2. Page 4, Figure 2 - a) in title of figure, change "1973-1995" to "1973-1983"
   b) change the vertical grid from "0, 1.0, 2.0, 3.0, 4.0" to "1.5, 2.0, 2.5, 3.0, 3.5".

3. Page 5, paragraph 6 - change "It has therefore included in the forecast..." to "It has therefore included a forecast...".

4. Page 17, paragraph 1 - change "small share of the total demand..." to "smaller share...".

5. Page 33, Figure 12 - in title of figure, change "marketable reserve (conventional producing area)" to "marketable reserves (conventional producing areas)".

6. Page 36, Figure 13 - change "marketable reserve" to "marketable reserves".

7. Page 46, last line - change "1:5,750 Mcf/d" to 1:5,750 MMcf/d.

8. Page 53, first paragraph - change "These price increases should be responsible..." to "These price increases should be responsive...".

9. Page 55, - lines 6 and 7, change "... new reserves in either areas and the flexibility..." to "...new reserves in either area and the inflexibility...".

10. Page 89, paragraph 3 - change "In these circumstances, if it is more efficient for TransCanada to the buyer..." to "In these circumstances, if it is more efficient for TransCanada to be the buyer...".

11. Page 89, paragraph 4 - change "...impairment of its ability of ..." to "...impairment of its ability to...".

12. Page 92, Photo title - "Image Ontario..." change to "Ignace Ontario...".

PREFACE

In recent times there has been growing public debate and concern about the outlook for the Canadian natural gas industry and on policy responses which would be appropriate to the current situation in the natural gas industry in Canada. An inquiry was therefore called on the Board's initiative in order to obtain a clearer insight into the short and long term outlook on the demand for, supply and deliverability of natural gas, as well as to evaluate criteria appropriate to the consideration of exports.

Sixty-two submissions were received from many segments of Canadian society and extensive public hearings were held across Canada commencing on November 12th, 1974 in Calgary and ending on March 5th, 1975 in Ottawa. Board staff has analyzed the material and conducted studies to sharpen the focus on the identification of the problems and to search for appropriate solutions.

The evidence indicates that Canadian demand for natural gas and existing exports commitments are virtually certain to exceed the supply available until the connection of natural gas from frontier areas or from other major new sources of supply if and when adequate reserves are available. A supply shortage has existed on the Westcoast Transmission system since 1973/74 and could occur on other systems as early as 1975/76; there were differences of opinion, however, as to when the shortage would occur and how large it would be.

Evidence on the ways of resolving the shortage of natural gas was less comprehensive and there were varied opinions on policies and actions needed to alleviate the situation.

The submissions and evidence narrowed the estimates of the time when frontier gas, if available, would be needed by Canadians, although there remained major uncertainties on the size of the resource base in the Canadian North, the rate of new discoveries which would be expected and on the cost of the gas if delivered to markets. If export commitments are to be met, frontier gas if available is needed as soon as it can be connected. Even if export commitments were abrogated, frontier gas would still be needed, for Canadian use, by the mid-1980's.

The Board invited an evaluation of the gas surplus calculation procedure developed and applied to assess export applications during the period of rapid growth of the natural gas industry. This procedure was applied to ascertain whether or not proposed exports exceeded "the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard . . . to the trends in the discovery of gas in Canada". It now appears, in light of the changing circumstances now unfolding, that more weight should have been given to deliverability, as distinguished from reserves; and that judgments as to the likely rate of new discoveries and of their deliverability characteristics both contributed to the present situation. In any event, some volumes being exported pursuant to existing licences are clearly not now surplus to Canadian requirements. We are in the position that long term export contracts running to some one trillion cubic feet a year, with a total of some 14 trillion cubic feet still committed to export are, in effect, a first charge on our production while Canadian requirements have to be satisfied from what is left over. This situation, if allowed to prevail, reverses the priority for Canadian requirements as set out in the National Energy Board Act.

A new approach to future exports is necessary. Tests of deliverability will be required not only prior to the issuance of licences, but periodically thereafter. If licences for additional exports are issued in the future, and this is conceivable if major discoveries are developed, they must be on a short term basis and conditioned so that Canadian requirements will have continuing priority.

PHOTO CREDITS

Consumers' Gas Company, Pg 1, Pg 67.

Imperial Oil Limited, Pg 96.

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Westcoast Transmission Company Ltd., Pg 75.

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RECITAL AND ORDER OF APPEARANCE

A public hearing in the matter of the supply, demand and deliverability of Canadian Natural Gas held pursuant to Part I of the National Energy Board Act.

File: 1122-2-1

HEARD at Calgary, Alberta on 13, 14, 15, 18, 19, 20, 21 November, 1974;

Winnipeg, Manitoba on 25, 26 November, 1974;

Toronto, Ontario on 3, 4, 5, 6 December, 1974;

Québec City, Québec on 9, 10 January, 1975;

Vancouver, British Columbia on 14, 15, 16, 17 January, 1975;

Ottawa, Ontario on 4, 5, 6, 7, 10, 11, 12, 13, 14, 17, 18, 19, 20, 21, 27, 28 February, 1975 and 3, 4, 5 March, 1975.

BEFORE:

M.A. Crowe	Chairman
C.G. Edge	Member
J. Farmer	Member

APPEARANCES:

Calgary	F.A. McKinnon J.H. Dagher A. LeBis	BP Canada Limited
	A.G. Bristow, Jr. J.G. Spratt J.A. Brickhill E.H. Gaudet	Chevron Standard Limited
	J. Andriuk E.A. Forques A.E. Potter W.G. Loewen	Dome Petroleum Limited
	C.R. Hetherington B. Sim	Panarctic Oils Ltd.
	P.R. Carpenter G.A. Little	PanCanadian Petroleum Limited
	H.J. Hewetson, D.F.C. M.J. MacDonald R.R. McDaniel G.C. Knutson	

Calgary	L. Waverman G.C. Watkins R.H. MacKie S.R. Blair W. Zboroluk D.H. Hushion P.R. Eilendson R. Gibbs	Foothills Pipe Lines Ltd.
	B.D. Cochrane D.G. Hart	Northern and Central Gas Corporation Limited
	G.F. Paschen	Canadians for Responsible Northern Development
	J.H. Fletcher D.M. Murray J.M. Hope	Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited
Winnipeg	P.O. Petursson A.L. Campbell	Greater Winnipeg Gas Company
	R.B. Ball J.F. Sherwood	Province of Manitoba
	J.W. Bruce R.D. Freeman J.A. Griffin	Saskatchewan Power Corporation
Toronto	J.R. Hardie G.A. Connell A.F.D. Short G.A. Holland	Gulf Oil Canada Limited
	D.W. Ross C.F. Osler	D.W. Ross & Assoc. Ltd.
	R.S. Lougheed J.H. Farrell	Consumers' Gas Company
	B.F. Willson D.E. Wood J.W.S. McQuat	Union Gas Limited
	A. Oliver L. Hansell Dr. J. Uvera F.J. Correy J.F. Howard	The Steel Company of Canada, Limited

Toronto	The Honourable W. Darcy McKeough J. Strong R.W. Macaulay	Ontario Ministry of Energy
	F.G.G. Bregha	Workgroup on Canadian Energy Policy
Québec City	J. Baladi T.E. Dancy C. Dufresne G. Barbeau C. Antaki	Gaz Métropolitain, inc.
	S.R. Blair S.A. Schmaltz C. Antaki	Pan-Alberta Gas Ltd.
	J.G. Fredette M. Masse G. Tousignant P.R. Fortin	Gouvernement du Québec
Vancouver	A.H. Willms J. Anderson G.H. Bowman A.A. Arneson C.D. Williams	Westcoast Transmission Company Limited
	W.R. Lee G.A. Constable D.R. McPhail	Canadian Resourcecon Limited
	R.K. Kidd D.R. Forrest J.A. Polson W.D. Mitchell	British Columbia Hydro and Power Authority
	R.B. Stokes D.R. McPhail	Inland Natural Gas Co. Ltd.
	R.M. Rutherford	Pacific Northern Gas Ltd.
	J.N. Robinson F.H.P. Dewdney	Cominco Ltd.
	G.T. Gallon	Canadian Scientific Pollution and Environmental Control Society
	E.M. Smith	E.M. Smith
	Dr. A.R. Thompson Dr. A. Hepworth A.J. Dingley I.G. Nathanson	British Columbia Energy Commission

Vancouver	Dr. J.F. Helliwell	Dr. J.F. Helliwell
	L. d'Easum	British Columbia Voice of Women
	J.L. Fingarson B.W. Threadgill C.F. Bentley F.M. Saville	Alberta Ammonia Ltd.
Ottawa	S.H. Clark H.S. Simpson G.A. Connell J.E. Baugh J. Ballem	Canadian Petroleum Association
	R.O. Pfister D.K. McIvor D.D. Lougheed L.C. Sevick J.C. Underhill J.M. Koshan	Imperial Oil Limited
	A.R. Nielsen J.A. Kelly D.W. MacFarlane	Mobil Oil Canada Ltd.
	Dr. R. Mattinson D.G. Stoneman L.J. Schofield J.M. Robertson	Shell Canada Limited
	V.L. Horte Dr. E.C. Sievwright Dr. J.R. Lacey D.M.M. Goldie	Canadian Arctic Gas Study Limited
	H.B. Sanderson D.R. Fenton J.T. Sullivan R.A. MacKimmie	Alberta and Southern Gas Company Limited
	S.R. Blair M.M. Kilik J.M. Connolly	Pan-Alberta Gas Ltd.
	R.S. Lougheed J.H. Farrell	Niagara Gas Transmission Limited
	E.T. Rimmer A. Sweatman	Inter City Gas Transmission Limited
	W. Hindle J.D. Houlding G.G. Francis	Polar Gas

Ottawa	G.W. Whidden L.H. Larson G.V. Rehwald J.M. Cameron E.W.H. Mallabone	TransCanada Pipelines Limited
	L.S. Stadler R.L. Billings B.A. Crane	Canadian-Montana Pipe Line Company
	J. Bousquet D. Lepage D.G. Hart	Celanese Canada Limited
	B.T. Johnson B. Hayton A.W. Birnie W.K. Voss J.G. Potvin	Industrial Gas Users' Association
	R.L. Bogardus G.G. Francis	Union Carbide Canada Limited
	W.S. Hunter A.D. Gardner	Ontario Hydro
	W.R. Anderson J.O. Torrens R.V. Robinson	Dupont of Canada Limited
	N.J. McNeill D.A.L. Britnell	Great Lakes Gas Transmission Company
	J.G. McMillian W.P. Diener	Northwest Pipeline Corporation
	E.C. Brown G.W. Benson	Canadian Industries Limited
	J.M. Robertson, Jr. R.V. Robinson	Midwestern Gas Transmission
	J.E. Squarek H.B. Alfaro F.G. Vetsch G.W. Cameron B. Mackie	Independent Petroleum Association of Canada
	A.M. Moore	Canadian Arctic Resources Committee
	I.A. McDougall A.J. Roman	Consumers' Association of Canada

DEFINITIONS

Several of the terms used in the natural gas industry are not always clearly defined and understood. The Board is therefore setting forth in this section on definitions, its understanding of the commodity value concept used in pricing. As well, the definitions of requirements, net sales, and the various definitions of reserves used in appraising supply and deliverability are outlined.

PRICING

Commodity value is a generic term to describe the value of natural gas in relation to available competitive fuels. In many cases, fuel oils today are the alternative, but electricity competes for the residential market and coal for part of the industrial. Since actual competition does not usually exist, value estimates can only be made by synthesizing a competitive situation. To be specific, commodity value should indicate:

a) The method of calculation:

A weighted average based on each market and end-use is a refined method; using a single fuel for a market such as "crude oil" or "No. 6 fuel oil" is a more approximate measure.

b) Because of the two-price system in effect for Canadian oil, whether world oil prices have been used or Canadian oil prices.

c) The point where the comparison is to be made; at the city gate (or refinery gate), or at the burner tip.

d) Whether burner tip efficiencies have been included; the usable heat from a given input of fuel varies according to the fuel.

e) Whether allowance has been made for premiums:

Natural gas as a fuel is said to command a premium because of its "form" value in comparison with other primary fuels. It is clean and does not require storage facilities, and the furnace and related equipment usually cost less than the corresponding equipment for burning oil or coal.
Premiums are hard to quantify but are often included in commodity value estimates.

In this report commodity value based on crude oil means a city gate value of a volume of natural gas equal to a refinery gate value of a quantity of crude oil having the same Btu content, without adjustment for differences in combustion efficiencies and "form" values; commodity value at the burner tip means a value of a volume of natural gas equal to a value of a quantity of an alternative fuel which, when burned, produces the same number of Btu's; parity at the burner tip means the "commodity value at the burner tip" of a volume of natural gas, plus a premium corresponding to the "form" value of natural gas in comparison with an alternative fuel.

TOTAL REQUIREMENTS

This refers to the total volume of natural gas consumed, or expected to be consumed, in all end-use sectors of the market, including pipeline fuel and losses, and reprocessing plant fuel and shrinkage adjusted to 1000 Btu/cf.

TOTAL NET SALES

This refers total requirements minus pipeline fuel and losses and reprocessing plant fuel and shrinkage.

ESTABLISHED RESERVES

The Board defines established reserves as those reserves which, on the basis of identified economic considerations and within a specified time frame, are considered to be recoverable with a high degree of certainty from known reservoirs, through the application of currently accepted recovery techniques. The Board's established reserves consist of its "proved" reserves together with some portion of its "probable" reserves. The term "established" has been in use historically by the Board with respect to natural gas, to clearly identify reserves which have been determined in a manner acceptable to it, and was recently extended to oil reserves, for purposes of consistency.

PROVED RESERVES

Proved reserves are those reserves considered to exist with a high degree of certainty. Volumes are mathematically calculated using dependable and well defined basic reservoir data.

The classification "proved" may be applied to any of in-place, recoverable and marketable reserves. Thus, for example, proved recoverable reserves are those considered to be recoverable with a high degree of certainty, on the basis of well defined reservoir data.

PROBABLE RESERVES

Probable reserves also are considered to exist with a high degree of certainty, but the basic reservoir data used in their calculation are less well defined. What constitutes proved reserves in contrast to probable is, to a considerable extent, a matter of professional judgment.

Again, this classification may be applied to in-place, recoverable or marketable reserves, indicating that less definitive reservoir data entered into their determination than for reserves in the proved category.

POSSIBLE RESERVES

Possible reserves are those to which a considerable degree of uncertainty is attached. The basic data used in their determination are not well defined, hence substantial speculation implied. The Board does not recognize possible reserves because of their speculative nature.

INITIAL RESERVES

Initial reserves are those present in a reservoir before any production from that reservoir has been deducted. Certain agencies use the synonomous terms "ultimate" or "original" reserves.

REMAINING RESERVES

Remaining reserves are those currently available from a reservoir at a particular point in time, making allowance for any volumes produced (i.e. cumulative production) to that time. Thus remaining reserves equal initial reserves less cumulative production.

IN-PLACE RESERVES

In-place reserves (commonly termed "gas in place") represent the total volume of gaseous substance occurring naturally in a reservoir without consideration of what portion may be recoverable.

RECOVERABLE RESERVES

Recoverable reserves represent that portion of the gas in place which is producible from a reservoir under anticipated technological and economic conditions, taking into consideration the geological and engineering characteristics of that reservoir. The adjective "raw" is often applied to recoverable reserves to eliminate ambiguity with marketable reserves. The ratio of recoverable reserves to in-place reserves, expressed as a fraction, is termed the "recovery factor".

MARKETABLE RESERVES

Marketable reserves are those volumes of natural gas available to the transmission line after removal, and to the extent necessary or desirable, of certain hydrocarbon and non-hydrocarbon compounds present in the raw volumes produced from the reservoir, and after allowance has been made for field and plant fuel and losses.

The ratio of marketable gas reserves to recoverable gas reserves, expressed as a fraction, is termed the "shrinkage factor".

Marketable gas is also commonly referred to as pipeline, residue or sales gas. Unless otherwise specified, established reserves of natural gas reported by the Board are marketable reserves.

BEYOND ECONOMIC REACH RESERVES

Reserves beyond economic reach are included in established reserves. As a rule they are located in areas where, under current and anticipated economic conditions, the prospect of their being marketed is unlikely. Historically, the Board has included half of the reserves beyond economic reach in its gas surplus calculation.

DEFERRED RESERVES

Deferred reserves are those volumes of established reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project, are not now available for market.

The Board, historically, has not included deferred reserves in supply for the purpose of the gas surplus calculation.

ULTIMATE POTENTIAL

This is the volume of natural gas which it is anticipated will have been discovered in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and future economic factors. A high degree of speculation and uncertainty is implicit in an estimate of ultimate potential, generally in inverse proportion to the geological knowledge of the area. Included in ultimate potential are volumes discovered and produced as well as those remaining to be found. Use of the term "potential reserves" as a synonym for ultimate potential is discouraged by the Board, since no justification exists for classifying undiscovered volumes as reserves.

RESERVES BASE PRESSURE AND TEMPERATURE

The Board calculates reserves at a pressure base of 14.73 psia and temperature of 60°F. Provincial agencies in Western Canada and the Canadian Petroleum Association use a pressure base of 14.65 psia. Reserves at 14.73 psia equate to reserves at 14.65 psia multiplied by a factor of 0.996. The standarrization of reserves to a base of 1000 Btu/cf eliminates the need for reference to a specific pressure base and temperature and for this reason is prefered by the Board for reporting purposes.

ABBREVIATIONS

Bcf	—	Billion cubic feet
Btu	—	British Thermal Unit
cf	—	cubic feet
GNP	—	Gross National Product
LNG	—	Liquified Natural Gas
MMcf	—	Million cubic feet
MMcfd	—	Million cubic feet per day
OPEC	—	Organization of Petroleum Exporting Countries
Tcf	—	Trillion cubic feet
25A4	—	The Board's existing formula for protection of Canadian domestic requirement for natural gas (25 x 4th year requirement)
The National Energy Board	—	The Board or NEB

CANADIAN REQUIREMENTS

Toronto as seen from the CN tower

INTRODUCTION

Of the sixty-two submissions received in response to the Board's Hearing Order of May 2nd, 1974, eight submissions provided forecasts of natural gas requirements in Canada based on a province by province analysis of energy consumption by sector of demand, (that is, residential, commercial, industrial, and power generation). Ten briefs provided estimates of requirements for all Canada only, or for a particular province or franchise area. In addition, the Board received a number of estimates related to the requirements of large industrial users.

The Board's Hearing Order set out the following three price assumptions as the bases for projections of the reasonably foreseeable requirements for natural gas:

(a) that the relationship between the price of natural gas and the price of competing fuels in each market area will remain unchanged from that prevailing on May 1st, 1974;

(b) that the price of natural gas will be equivalent to the price of crude oil, in the same market area, on a Btu — content basis: and

(c) that the relationship between the price of natural gas and the prices of competing fuels will be such as the submittor thinks will likely pertain, stating clearly the assumptions used.

Not all submittors provided estimates of requirements under all three assumptions. The interpretation of price assumption (b) varied somewhat among the submittors and, in addition, there was a variety of opinion as to the most likely price relationship that would or should exist in the future.

Interpretation of price assumption (b) varied as to the time at which equivalence on a Btu basis would be attained. Some forecasts were based on immediate price equivalence while others assumed a gradual phase-in to Btu price equivalence between gas and oil. Some submittors interpreted price assumption (b) to mean price equivalence of crude oil at the refinery and natural gas at the city gate in each market area. Others assumed this type of price equivalence in Toronto with gas being priced lower than oil in Alberta, Manitoba, Saskatchewan and Northern Ontario, because of the lower cost of transporting oil to these areas relative to gas. Other submittors, notably the Canadian Petroleum Association (CPA), interpreted price assumption (b) to mean price equivalence of petroleum products and natural gas at the burner tip in each end-use sector. Others, among them the British Columbia Energy Commission, (B.C. Energy Commission) assumed price

equivalence in the commercial and industrial sectors, but not in the residential sector.

There was a considerable divergence of opinion as to price assumption (c). The CPA assumed natural gas should be priced to reflect its premium value. This would result in residential gas prices, for example, being 50 percent higher than oil prices in this sector. At the other extreme, Gaz Métropolitain, inc. (Gaz Métropolitain) assumed that natural gas at the burner tip should be priced lower than competing oil products.

Some submittors provided only one forecast and in some cases, notably Gulf Oil Canada Limited (Gulf) and D.W. Ross & Assoc. Ltd. (D.W. Ross), did not specify the assumptions as to price in terms of the Board's three cases. Such forecasts could be interpreted as having been submitted as price assumption (c). However, for purposes of comparison in the following graphs of total requirements for Canada, the Board has, for some submittors, interpreted their forecasts as being within a rather wide definition of price assumption (b).

Figures 1 and 2 compare the various forecasts of Canadian requirements for natural gas under price assumption (b). In this graph Shell Canada Limited (Shell) Scenario (b) is depicted although there is no change in relative gas and oil prices between Shell's Scenarios (b) and (c). BP Canada Limited (BP) provided an estimate of total net sales but did not provided an estimate of compressor fuel, company losses and reprocessing shrinkage and thus their forecast is not shown on the graph. The CPA forecast is the highest in every year reflecting their optimistic expectations regarding Canada's expected rate of growth in population and economic activity and their expectation that, under equivalent pricing for oil and natural gas, gas would achieve a significantly higher share than oil to total fossil fuel demand. Professor John Helliwell of the University of British Columbia provided the lowest forecast of total requirements over the period 1978 to 1986. This results from his assumption that significant increases in gas prices between 1972 and 1975 will reduce the trend rate of post-1978 gas demand from eight percent to five percent. In addition, further price increases in the price of gas relative to the general price level are assumed in his model to reduce the growth rate to about two percent in 1978 and 1979. Although BP did not submit a total requirements estimate (including fuel, losses and shrinkage), their forecast of total net sales is the lowest of all in the case of price assumption (b). Most submittors did not include an allowance for fuel for an Arctic pipeline.

Under price assumption (c), despite different expectations as to the most likely price, those submittors who provided a forecast of total net sales for Canada tabled remarkably similar

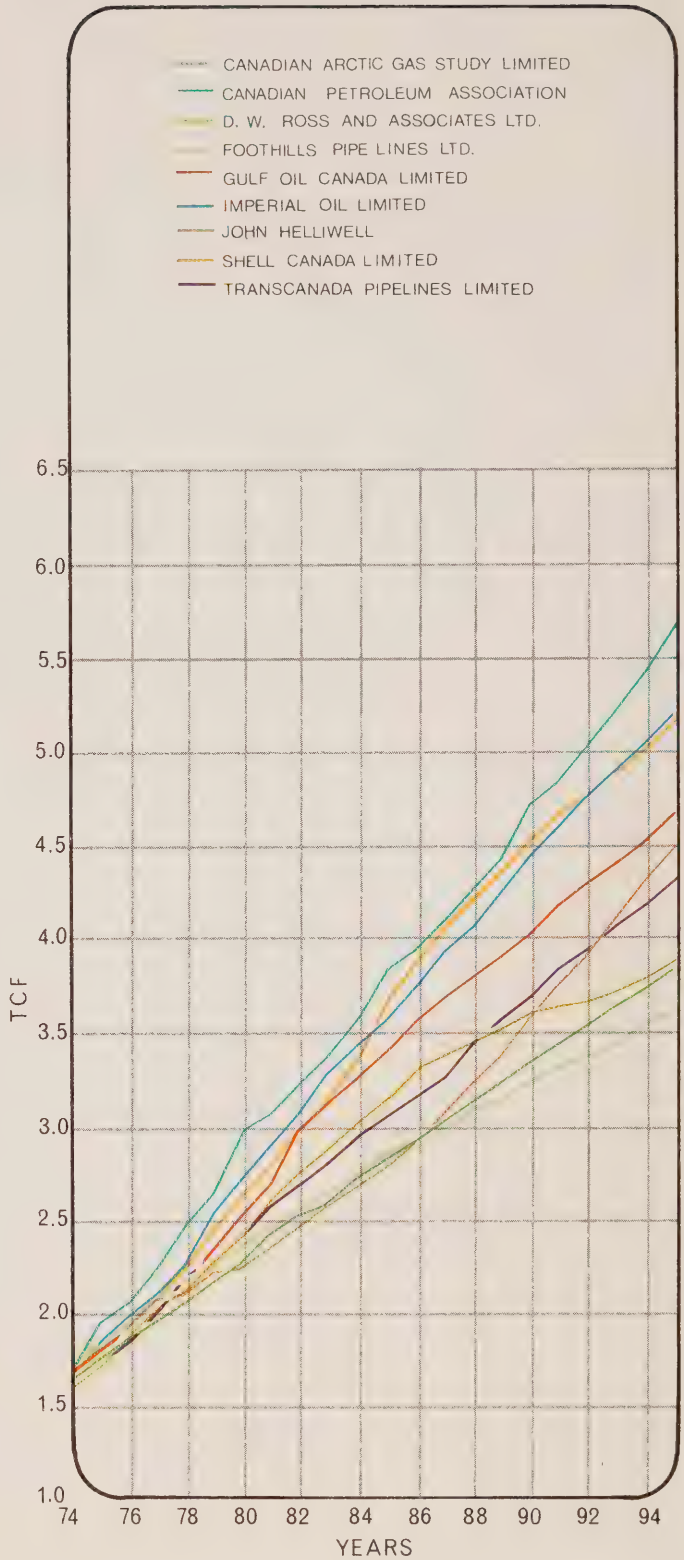


Figure 1

COMPARISON OF FORECASTS OF NATURAL GAS TOTAL REQUIREMENTS, CANADA
1973-1983 (PRICE ASSUMPTION B)

forecasts, ranging, in 1995, from a low of 3.0 Tcf to a high of 3.8 Tcf.

Despite the similarity of forecasts of total demand for Canada, there were very significant differences among the forecasts for particular end-use sectors or particular provinces. The submittors' views for each province are described below.

Comparison of projections based on price assumptions (a) and (b) reflected a wide variety of opinion as to the price sensitivity of demand. The relative price stability of the 1960's results in a data base inadequate for the measurement of such sensitivity. The variation of opinions as to sensitivity is, therefore, understandable. It is also recognized that most of the projections of natural gas requirements had to rely, to various extents, on historical patterns of market growth, which may have limited relevance to future developments in the energy field. This fact introduces the possibility of large errors in addition to the errors inherent in every forecast.

With regard to the three price assumptions, the Board is of the opinion that a continuation of price relationships in existence as of May 1st, 1974, is unlikely. The Board sees, then, price assumption (a) as having limited validity. The views of the Board with regard to future Canadian natural gas requirements are therefore based on price assumption (b), price equivalence with oil on a Btu basis, with Toronto as the point of reference. At the time of preparation of this report, this price condition is the one most likely to prevail. It is also assumed that the Btu equivalent price will be achieved within a time frame of about three years which should mitigate the disruptive effects of rapid price changes. Several submittors proposed that natural gas prices rise to full "parity" with OPEC oil prices, including a premium for natural gas.

In light of the large number of plans for the development of a Canadian petrochemical industry, the summary of the relevant evidence on Canada's natural gas requirements and views of the Board shown in this chapter are divided into two parts; one deals with the residential, commercial, industrial (excluding petrochemical) and thermal-electric market in each province, while the second discusses the potential new markets for natural gas, particularly as a feedstock for the manufacture of petrochemicals and ammonia.

A summary of the Board's views and the forecast of total Canadian requirements is provided at the end of this chapter.

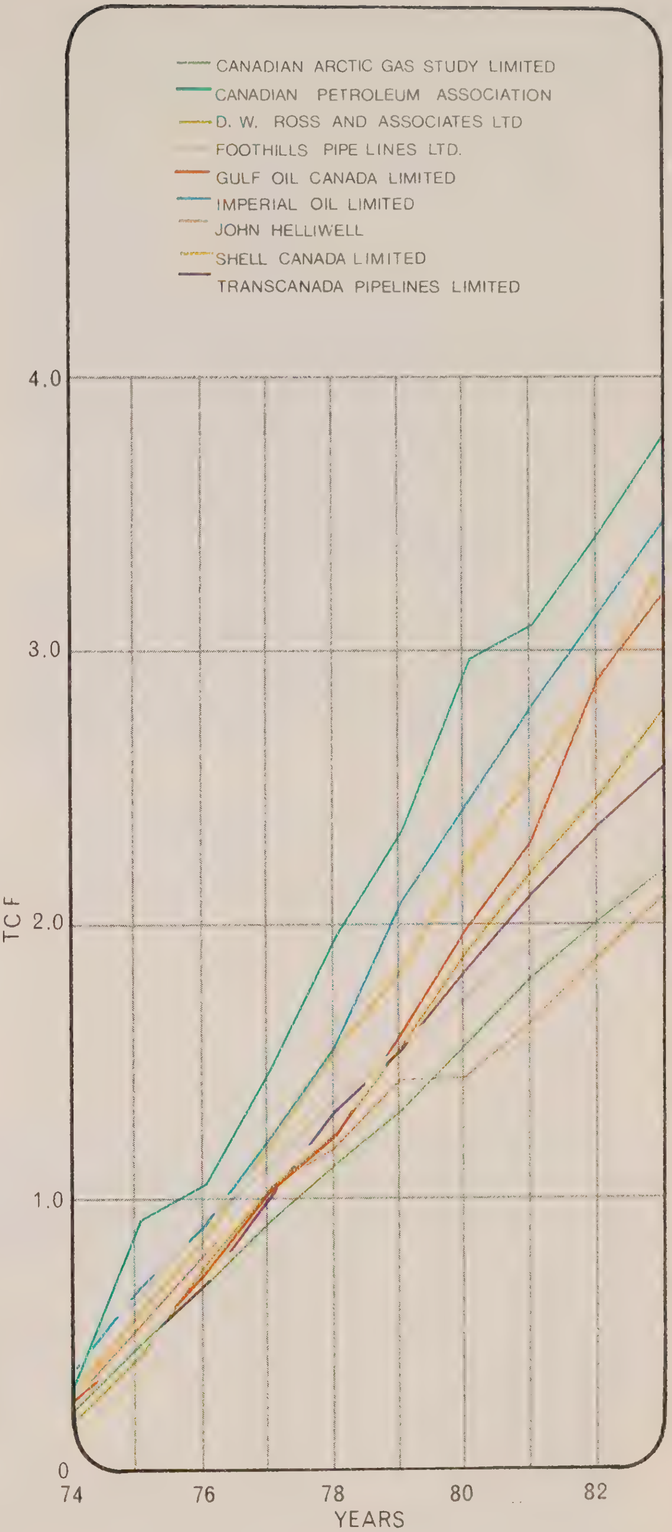


Figure 2
COMPARISON OF FORECAST OF NATURAL GAS TOTAL REQUIREMENTS, CANADA
1973-1995 (PRICE ASSUMPTION B)

DEMAND FOR NATURAL GAS (EXCLUDING PETRO-CHEMICAL DEMAND)

a) BRITISH COLUMBIA

(i) *Views of Submittors*

The forecasts of natural gas net sales for British Columbia based on price assumption (b), vary widely throughout the forecast period. By 1995 the high estimate of 771 Bcf submitted by CPA is more than double the low estimate of 370 Bcf submitted by Westcoast Transmission Company Limited, (Westcoast). The variations reflect mainly the differences in opinion as to anticipated population growth, industrial activity and penetration of the market by natural gas in that province. In addition, there are two specific issues which may partly account for the considerable variations among the forecasts.

The first of these is the question of gas service being extended to Vancouver Island and the prospective timing of such a development. Not all submissions made specific reference to it, but four projections made the explicit assumption that gas service will be available in Vancouver Island by 1981.

The second issue is the natural gas requirement for thermal-electric generation in the British Columbia Hydro and Power Authority (B.C. Hydro) Burrard generating station. Some of the submittors were of the opinion that the existing large water storage potential would eventually reduce the use of gas in the Burrard station, while others projected slight increases in natural gas use by additional gas turbines. Forecasts of natural gas requirements for thermal generation in 1995 range from a low of five Bcf (D.W. Ross) to a high of 40 Bcf (Westcoast) and Canadian Resourcecon Limited (Canadian Resourcecon).

In the residential/commercial sector, forecasts vary widely from 146 Bcf (Foothills Pipe Lines Ltd. (Foothills)) to 298 Bcf (CPA).

With regard to pricing, the B.C. Energy Commission stated that natural gas prices, due to the pricing policy of the provincial government, would not reach Btu equivalence with oil in the residential sector.

(ii) *Views of the Board*

The Board is of the opinion that service to Vancouver Island is unlikely to commence before 1981. It has therefore included in the forecast of gas requirements similar to that forecast by TransCanada Pipelines Limited (TransCanada) and Canadian Resourcecon, adjusted for the time lag in the commencement of service.

The Board assumes that gas in British Columbia will be priced at equivalence with oil after a phase-in period of three years, with one exception. It is anticipated that gas prices at the burner tip to residential customers will be set below the price of fuel oil due to the policy of the B.C. Government. The Board's forecast assumes an increasing market share for gas in all sectors during the phase-in period with a continuance of penetration in the residential sector throughout the forecast period. Industrial demand for gas is expected to grow at a slower rate in the latter half of the forecast period due to the greater use of coal and fuel oil as a result of higher gas prices and of the mature stage of development of that province's forest resources.

It appears that the B.C. gas requirement for thermal electric generation could be of the order of 23 to 25 Bcf in the period 1976 to 1985 and increase to about 35 Bcf by 1995. However, if gas were available in the winter as well as the summer months, then the Canadian Resourcecon forecast of about 31 Bcf in 1976 increasing to approximately 40 Bcf by 1995, would be reasonable.

The demand for natural gas in B.C. for each sector is set out in detail in Tables 6 and 7.

b) ALBERTA

(i) *Views of Submittors*

The projections, in general, reflect the existing high penetration of the market by natural gas, which precludes further large increases in sales volumes at the expense of other fuels. The main divergence in opinion is, therefore, with regard to the future growth of the market resulting from the accelerated industrial development program in Alberta.

In addition to the degree and speed of industrial development and the resulting population growth in general, a particular area of uncertainty is the future natural gas requirement for oil sands plants. This is illustrated by the greater variation in the industrial forecasts as compared with the residential/commercial forecasts. In the other industrial sector, forecasts for 1995 vary from 97 Bcf forecast by D.W. Ross to 297 Bcf (adjusted for petrochemical demand) forecast by Foothills. In the residential/commercial sector, on the other hand, the range is from 229 Bcf (TransCanada) to 398 Bcf (D.W. Ross).

Variations in natural gas requirements for thermal generation were due to differences in the forecast assumptions used. Some submittors predicted a continuing use of gas due to future additions of gas-fired peaking capacity, while others felt that gas demand would be reduced because it would no longer be used for base load thermal generation but for peaking purposes only. Still others assumed that gas would be drastically curtailled by 1980 and used only for flame stabilization purposes. The forecast of natural gas requirements for thermal generation varied from five Bcf forecast by Shell to 88 Bcf forecast by Canadian Arctic Gas Study Limited (CAGSL) and TransCanada.

Most of the submittors expressed the opinion that the most appropriate price assumption for Alberta is that natural gas will remain priced lower than oil on a Btu equivalent basis.

(ii) *Views of the Board*

The Board expects that natural gas in the residential and commercial sectors will be priced lower than oil due to the expected continuation of the Alberta rebate program for customers using less than one Bcf of gas per year. Natural gas will be priced lower than oil in the industrial sector due to the assumption of equal prices on a Btu equivalent basis applying in Toronto, and the fact that transportation costs of oil are lower than those of gas.

Despite the favourable pricing conditions, growth in the residential and commercial sectors is lower than in other provinces because of the currently high market penetration of gas. Growth in demand in the industrial sector (excluding petrochemical demand) is expected to be above the national average due to the greater than average growth in industrial activity in the province as a result of petrochemical and oil sands activity.

Natural gas requirements for oil sands plants have been forecast to rise to 22 Bcf by 1979. The Board expects that this requirement will be reduced to zero by 1986 as it is the Board's view that all oil sands plants will be using petroleum coke produced as a by-product of the oil extraction process by that time.

The review of all pertinent information for gas requirements for thermal generation for Alberta indicates that the estimates prepared by the Alberta Energy Conservation Board, (Alberta Board) and referred to by several submittors are reasonable. These estimates indicate a gas requirement of 56 Bcf in 1976 growing to 87 Bcf by 1995.

The Board's forecast of gas requirement for each sector is shown in detail in Table 8.

View of Edmonton

c) SASKATCHEWAN

(i) ***Views of Submittors***

The two basic factors having a major influence on natural gas requirements in Saskatchewan are population and the potash industry.

The main uncertainty with regard to population is whether the declining trend in population, due to emigration, can be expected to continue during the forecast period, to reverse, or, after a period of continuing decline, to stabilize. In spite of this uncertainty, there is little variation in the forecasts of natural gas requirements in the residential/commercial sector in 1995. With one exception, all forecasts lie between the extremes of the 52 Bcf forecast by BP and the 66 Bcf forecast by TransCanada. The exception is Shell's forecast of 91 Bcf, which results from the assumption of a relatively high growth rate in the residential sector.

Some of the submittors have given specific consideration to the potash industry since Saskatchewan accounted for approximately 21 percent of total world production of potash in 1973. Others did not separately analyse the potash industry, but forecast only the total industrial natural gas requirement. CPA submitted the lowest forecast for industrial demand, 65 Bcf, while the TransCanada forecast was the highest at 151 Bcf in 1995.

With respect to natural gas requirements for thermal generation, some forecasts showed a constant or slightly increasing use of gas based on the absence of supply constraints for natural gas as well as the use of gas to balance the energy requirements of the integrated hydro system under average river flow conditions. Other submittors forecast gas reductions due to supply constraints and the increased use of coal-fired generation to balance the system energy requirements. By 1995 the forecasts varied from a low estimate of 5 Bcf by D.W. Ross and TransCanada to a high estimate of about 25 Bcf expected by CPA and Shell.

(ii) ***Views of the Board***

Estimates of residential and commercial demand forecast by all submittors (except Shell) using different methods were essentially the same. The Board has adopted the growth rates forecast by the Saskatchewan Power Corporation as being representative. Growth in these sectors is expected to be modest reflecting a stable population and the present high market share held by gas.

The Board expects a rapid expansion in potash output in Saskatchewan and agrees generally with the estimates of gas required for processing potash provided by those submittors who took specific account of this factor. The Board expects that by 1995 gas used for potash production will account for more than one half of the total industrial demand.

The Board expects that gas used for thermal generation will be 15 Bcf throughout the forecast period if no supply constraints are assumed.

The Board's forecast of gas requirements for each sector is shown in detail in Table 9.

d) MANITOBA

(i) ***Views of Submittors***

Natural gas service in Manitoba has historically been limited to those southern areas of the province adjacent to the TransCanada system. The bulk of natural gas end-use sales in the province are made by Greater Winnipeg Gas Company (Greater Winnipeg Gas) to customers in and around Winnipeg.

Forecasts of total gas requirements in the province in 1995 (based on the Board's price assumption (b)), ranged from a low of 96 Bcf (BP) to a high of 208 Bcf (Shell). The latter forecast is 59 Bcf higher than any other forecast, primarily by virtue of the fact that Shell's residential/commercial forecast exceeds all others by at least 100 Bcf. Although there was a wide range of estimates for the residential/commercial sector in Manitoba, most of the submittors' estimates centered around 72 Bcf. In the industrial sector, forecasts varied from 27 Bcf (D.W. Ross) to 70 Bcf (CPA) in 1995.

Natural gas requirement for thermal generation in 1995 was forecast to be less than one Bcf by all submittors other than CPA, which forecast a requirement of seven Bcf in that year.

Greater Winnipeg Gas submitted a forecast to 1995 for its franchise area only. Since approximately 75 percent of net sales of natural gas in Manitoba in 1973 were made in this franchise area, it is of value to note Greater Winnipeg's forecast consumption in the residential/ commercial market of 59 Bcf and in the industrial market of 22 Bcf, for a total requirement of 81 Bcf in its franchise area.

(ii) *Views of the Board*

In the residential/commercial sector the Board adopted the rate of growth implicit in the TransCanada potential demand case as being representative of the results obtained by the majority of submittors.

The Board found a substantial deviation in the various submittors' views of demand in the industrial sector. In consequence, the Board has adopted a simplified approach which relates the growth in industrial demand to the potential real GNP growth for Canada.

The Board expects that the gas requirements for thermal generation in the period 1975-1995 will be in the order of one Bcf per year. In addition, if large summer surpluses should occur in the future, it can be expected that gas requirements could increase to three or four Bcf per year.

The low growth rate in the Board's forecast in total net sales, relative to some other provinces, appears reasonable in the light of expected low growth in population combined with increasing penetration of electric heating in the residential sector as fossil fuel prices move upward.

The Board's forecast of gas requirements for each sector is shown in detail in Table 10.

e) ONTARIO

(i) *Views of Submittors*

In 1973, approximately 50 percent of net sales of natural gas in Canada occurred in Ontario, making this province a critical factor in any forecast of future requirements.

Forecasts of net sales in Ontario in 1995 vary from 1,369 Bcf (GAGSL) to 2,141 Bcf (Shell). These variations are a result of different perceptions as to the effects of higher gas prices on demand, and uncertainty as to the prices to end-users of competing fuels and electricity which will result from Btu price equivalence with crude oil.

In the residential/commercial sector, forecasts for 1995 range from a low of 472 Bcf (Foothills) to a high of 1,770 Bcf (Shell). The latter forecast is more than double that of any other submittor. This results from its assumption that the convenience and cleanliness of burning gas together with lower associated capital costs will result in it being the preferred fuel.

Shell submitted two forecasts in which the relative gas/oil prices are the same but the absolute price levels of the fuels differ. In Shell's Scenario (c), gas and oil prices are assumed to be equal but priced considerably higher than present levels. It assumes that conservation and a greater use of electricity will reduce the demand for gas in the residential/commercial sector from 1,770 Bcf in 1995 to 1,027 Bcf when commercial. The D.W. Ross study on behalf of the Ontario Government and three Ontario gas distributors forecasts a requirement in these two sectors ranging in 1995 from 328 Bcf to 773 Bcf depending on electricity prices.

In the industrial sector, forecasts range from a low of 325 Bcf in 1995 submitted by Shell to a high of 992 Bcf submitted by CPA. The D.W. Ross study presents a range of 512 to 626 Bcf. The relatively low forecast by Shell reflects that submittor's view that under crude oil and gas Btu price equivalence, heavy fuel oil would be priced below the price of gas sold to industrial users. Under such pricing conditions, oil would capture most of the incremental growth in the industrial market. Imperial Oil Limited (Imperial Oil), on the other hand, submitted that under crude oil and gas Btu price equivalence, gas would be priced substantially lower than heavy fuel oil, and thus gas would capture a greater share of the market.

Natural gas requirements for thermal generation were forecast by some submittors to remain relatively constant at 40 to 50 Bcf based on a continuation of the present gas sales contract, the maintenance of the present air quality regulations, and Ontario Hydro's need for fuel diversity for reasons of security of supply. If air quality regulations are made more stringent, the requirement could increase to 100 Bcf per year. D.W. Ross however, argued that gas use would taper off from 45 Bcf to 10 Bcf by 1995 due to the retirement of the gas fired units at the Hearn plant. Others (Gulf and Shell) estimated that gas would be completed phased out due to gas price increases as well as gas supply constraints. By 1995 the forecasts of gas requirements for thermal generation ranged from zero to 100 Bcf.

(ii) *Views of the Board*

The Board found a considerable divergence of opinion with regard to the demand for gas in Ontario. The uncertainties of the forecast are underscored by the large variation in the demand under the same gas/oil price ratios, but different price levels, submitted by Shell. In addition there is considerable divergence of opinion within the industry

Night view of Montreal

as to the price relationships between oil and gas at the burner tip which will result from crude oil and gas equivalency on a Btu basis.

The Board's forecast of potential demand assumes that gas will increase its penetration of all markets at the expense of oil until gas is priced at the Btu equivalent of crude oil. After that time the burner tip prices are assumed to result in slightly higher market shares for gas in relation to the incremental demand for fossil fuels in the residential and commercial markets. Under these conditions the Board expects a residential/commercial demand of 627 Bcf by 1995 and an industrial demand (excluding petrochemicals) of 889 Bcf.

If a shortfall of oil occurs in the mid-1980's, and gas supplies are available, then the demand in all sectors could be considerably in excess of all the forecasts submitted to the Board.

After examination of all the relevant evidence related to Ontario Hydro requirements for gas, it appears that the Ontario Hydro forecast of potential demand of 115 Bcf from 1978 to 1981 declining to 95 Bcf by 1995 is reasonable.

The Board's forecast of Ontario's requirements by sector is presented in detail in Table 11.

f) QUEBEC

(i) *Views of Submittors*

Natural gas distribution in Quebec is limited, at the present time, to Montreal and environs, the City of Hull and the Rouyn-Noranda area. Forecasts of future natural gas requirements in Quebec are dependent on the assumptions made concerning the expansion of the present distribution system into other areas of the province. As a result of the varying assumptions made in this regard, the forecasts of residential/commercial and industrial requirements submitted exhibit a greater variance than might otherwise have been expected.

D.W. Ross, for example, assumes no expansion beyond existing markets. On the other hand, the Quebec Government, as a specific policy objective, wants natural gas to significantly increase its share of total energy consumption from five percent in 1973 to about 20 percent by 1995 in order to provide a more balanced energy structure. The requirement forecast for 1995 by the Québec Government is less than half of the forecast by the CPA which made an assumption similar to that of the Québec Government. Gaz Métropolitain and the Government of Québec differed somewhat as to the expected timetable for expansion of the existing service area. The Government of Québec submission forecast expansion to Bécancour in 1975 and to Québec City in 1978 while Gaz Métropolitain showed service to the two areas commencing one year later.

The Government of Québec and Gaz Métropolitain forecasts differed substantially under the Board's price assumption (b). Gaz Métropolitain stated that a 15 percent price margin in favour of natural gas would be necessary for significant expansion while the Government of Québec submissions indicated a substantial market for gas under price assuption (b), especially in the industrial markets. An extensive survey of potential customers for gas presented in a supplementary submission by the Government of Québec indicated a greater potential for gas than that presented in the original Québec submission.

Forecasts of natural gas requirements in 1995 under price assumption (b) in the residential/commercial sector ranged from 80 Bcf submitted by Gaz Métropolitain to 396 Bcf submitted by CPA. The industrial requirements forecast varied from a low of 94 Bcf submitted by Shell to a high of 561 Bcf submitted by CPA. The Government of Québec forecast a demand of 185 Bcf in the residential/commercial sector and 253 Bcf in the industrial sector in 1995.

None of the submissions forecast a natural gas requirement for thermal generation in the province.

(ii) ***Views of the Board***

The Board has adopted the views of the Québec Government on expansion of the market area as to the sequence of towns to be served, but considers that the expansion is likely to be lagged by two years. The Board's forecast assumes gas service to Bécancour in 1977 and that gas would reach Québec City in 1981.

The Board considers that total sales will be 402 Bcf by 1995 compared with the 1974 level of 80 Bcf. Most of the growth is expected to occur in the industrial sector.

The Board's forecast of Québec's requirements by sector is presented in detail in Table 12.

NATURAL GAS REQUIREMENTS FOR PETROCHEMICAL PRODUCTION

It has become increasingly evident that natural gas will be called upon in the future to play a more important role in the production of petrochemicals in Canada. The Board decided, therefore, under item I (iii) of its Notice of Hearing, to ask interested parties to file submissions regarding reasonably foreseeable requirements of natural gas for the years 1973-1995 inclusive, for the production of ethylene through ethane extraction and for the production of ammonia, methanol and "other chemicals".

(i) ***Views of Submittors***

Out of a total of sixty-two submissions, only twenty-three discussed or provided estimates of natural gas requirements for petrochemical production. The depth of coverage varies widely. The majority believes that most of the additional petrochemical production capacity in the future will be located in Alberta.

Five submittors gave estimates of natural gas requirements for petrochemical production in Canada as a whole. Only one of these five submittors explicitly included both feedstock and fuel requirements while only two submittors offered estimates for the category 'other chemical feedstock'. Furthermore, some of those who provided estimates of total petrochemical requirements did not give separate estimates for the various petrochemicals, namely, ethylene, ammonia and methanol, and only one submitted an estimate of the outputs. The main estimates have been summarized in Table 4.

Generally the submittors were of the view that even first stage upgrading of resources was beneficial to Canada, that such upgrading was essential and that it would lead to further upgrading with substantial additional benefits to Canadians. However, no hard data was entered as evidence to support these arguments. With few exceptions the submittors thought that feestock prices were not an important determinant in the decision to set up new petrochemical capacity, although some anticipate possible adverse competition in the 1980's in domestic and foreign markets from OPEC producers having access to lower feedstock costs. They therefore requested that Canadian feedstock gas prices be no higher than the rolled-in price in the United States. The other submittors, however, were of the view that it would not be in the Canadian public interest to subsidize the cost of feedstock gas.

Submittors were also not certain about the future posture of the United States Government with regard to trade and tariff barriers. However, the existence of a market in the United States, due to a shortage of feedstocks and the expense of those feedstocks, is considered to be the major impetus for the installation of additional petrochemical capacity in Canada. It is also generally recognized that the establishment of these world-scale petrochemical plants is predicated on exports being permitted for some years until the size of the Canadian market matches the capacity of the Canadian petrochemical industry. In addition to the availability of the export

market, the assured supplies of feedstocks in Alberta, coupled with the desire of the Government of Alberta to foster the development of a petrochemical industry within the province, seemed to be the primary reasons for the current consideration of a large number of projects within the province. The fact that Alberta is the preferred location for petrochemical production necessarily limits the choice of feedstock to natural gas in the near term, since Alberta cannot as yet provide a ready market for co-products if naphtha is used as feedstock. This is particularly so in the case of ethylene.

(ii) *Views of the Board*

The Board concurs with the general view that Canada should encourage maximum upgrading of its resources provided that plants being set up are based on sound economics so that they could compete internationally and the newly added capacity does not result in serious over-production relative to domestic consumption.

The problem of how much capacity is optimal at any one time is uncertain. This includes the possible use of new technology (the use of synthetic gas as feedstock), the attitude of the United States towards trade and tariff barriers and the cyclical nature of petrochemical demand in North America. There is also insufficient knowledge of how much gas there is in the frontier areas of Canada, when it could be connected to the markets and the cost of such gas when landed in the market place. Furthermore, in contemplating new capacity the longer-run implication of OPEC competition in the 1980's arising from lower feedstock costs cannot be safely disregarded.

Moreover a tight gas deliverability situation is likely to prevail in Canada in the near and medium term, a period when major new petrochemical plants are planned to go on stream. In view of all this the Board is of the opinion that it would be in the public interest of Canada to adopt a cautious approach in considering future petrochemical capacity.

The most probable forecast of reasonably foreseeable natural gas requirements for petrochemical production arrived at by the Board is shown in Table 5. This forecast is based, among other things, on the assumption that additions to existing Canadian petrochemical capacity will take place in the manner shown below.

The Board staff carried out an analysis of the interactions of different demand and supply scenarios under varying sets of assumptions. The results of this analysis are illustrated in Figures 3, 4, 5, 6 and 7. In these figures estimates of future domestic requirements for various petrochemicals are provided within boundaries of high and low possibilities to reflect the difficulty at this stage of deriving precise estimates. Current plans to expand ammonia capacity are a special concern to the Board since the evidence seems to indicate that the construction of five world-scale ammonia plants in Canada will result in plants being build almost exclusively to serve the export market. The Board recognizes that reasonable prospects for petrochemical export can be entertained in the near

ADDITIONAL GAS-BASED PETROCHEMICAL CAPACITY

(all in Alberta)

Product	Year of Implementation	Plant Capacity	Total Added Capacity
Ethylene	1977	1.2 billion pounds	1.2 billion pounds
	1980	1.2 " "	2.4 " "
Ammonia	1976	400 (thousand) short tons	400 (thousand) short tons
	1977	400 " " "	800 " " "
	1978	400 " " "	1200 " " "
	1985	400 " " "	1600 " " "
	1990	400 " " "	2000 " " "
Methanol	1975	200 " " "	200 " " "
	1977	200 " " "	400 " " "
	1995	100 " " "	500 " " "

April, 1975

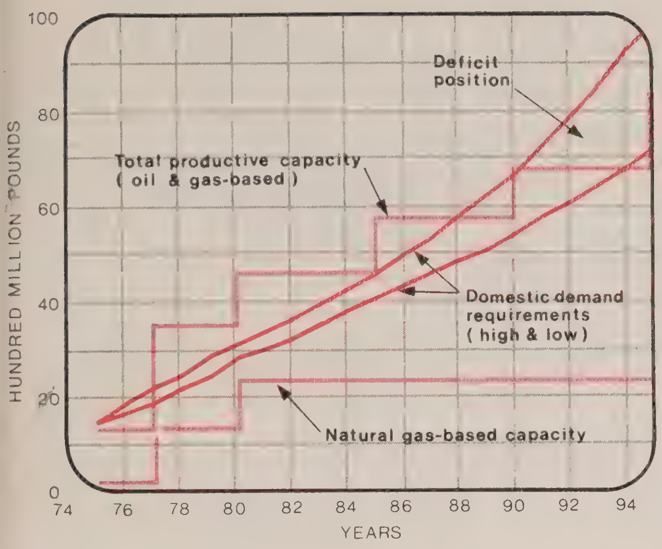


Figure 3
NEB FORECAST OF TOTAL NATURAL GAS REQUIREMENTS FOR PRODUCTION AND DISPOSITION OF ETHYLENE, FOR CANADA,
1975-1995 (HUNDRED MILLION POUNDS)

and medium term. It urges caution however, in expanding ammonia capacity since the realization of current plans would be tantamount to a significant increase over existing gas export levels.

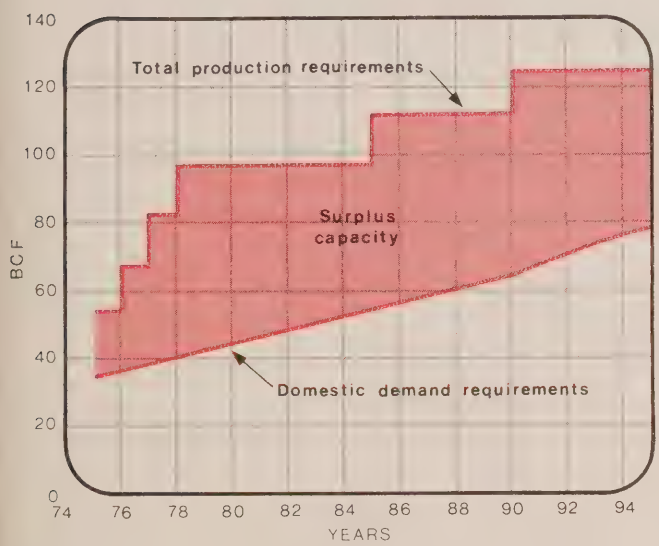


Figure 4
NEB FORECAST OF TOTAL NATURAL GAS REQUIREMENTS FOR PRODUCTION AND DISPOSITION OF AMMONIA, FOR CANADA,
1975-1995 (LOW CASE)

The Board expects that the construction of the gas-based ammonia plants will not proceed as rapidly as the Alberta Board predicts in its Report 74-W, "Appendix 2, Alberta Requirements of Energy and Energy Resources, 1975 – 2004", dated March, 1975. The Board has forecast an additional three gas-based world scale ammonia plants in Alberta by 1978 and a further two plants by 1990. The Alberta Board has forecast six additional plants by 1978, with no further gas-based plants thereafter.

The Board projects that the total natural gas requirements for feedstocks and fuel for the production of ethylene, ammonia, methanol and other chemicals in

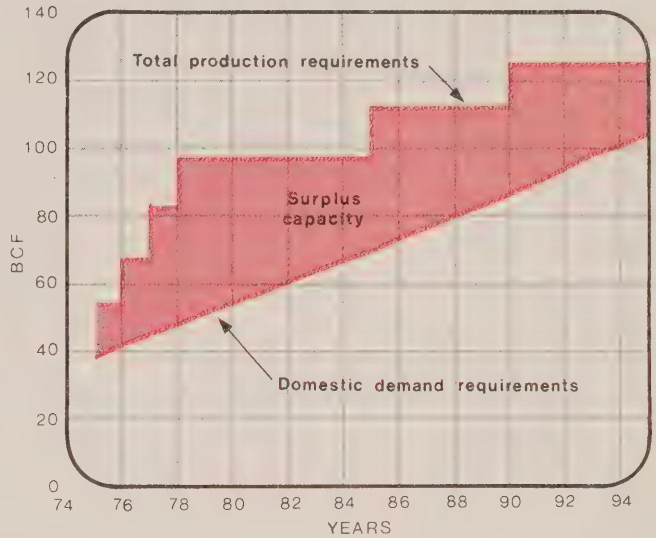


Figure 5
NEB FORECAST OF TOTAL NATURAL GAS REQUIREMENTS FOR PRODUCTION AND DISPOSITION OF AMMONIA, FOR CANADA,
1975-1995 (HIGH CASE)

Canada will increase from 76.3 Bcf to 287.6 Bcf in 1995. Except for a modest increase from 24 Bcf in 1974 to 28 Bcf in 1995 for the Province of Ontario, the rest of the increase in requirements is expected to take place in Alberta.

SUMMARY AND FORECAST OF NATURAL GAS DEMAND IN CANADA

Forecasting the demand for a commodity over a twenty year period is always a hazardous task. Moreover, the prices of all forms of energy are undergoing substantial changes, relative prices of various fuels at the burner-tip are changing, and the extent to which new conservation programs will reduce energy

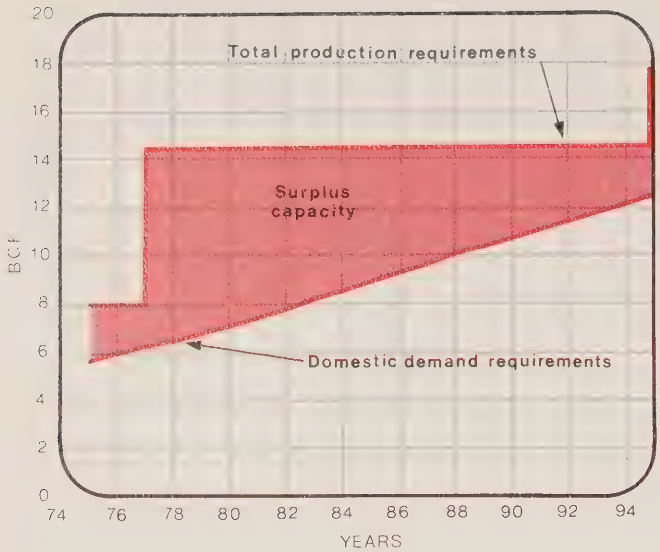


Figure 6
NEB FORECAST OF TOTAL NATURAL GAS REQUIREMENTS FOR PRODUCTION AND DISPOSITION OF METHANOL, FOR CANADA,
1975-1995 (LOW CASE)

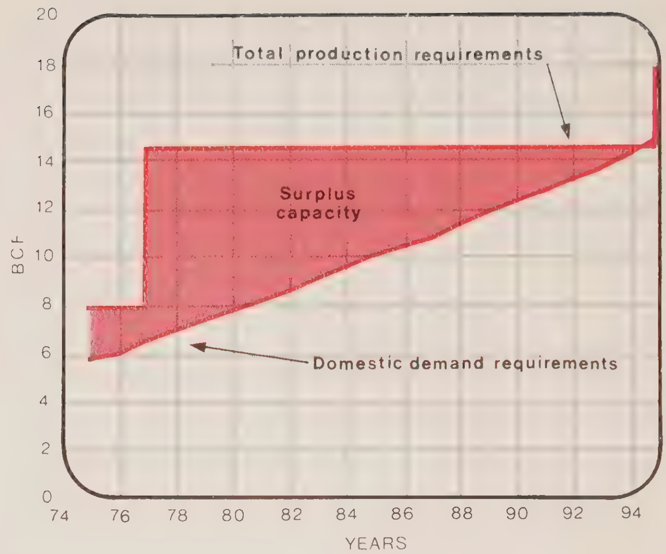


Figure 7
NEB FORECAST OF TOTAL NATURAL GAS REQUIREMENTS FOR PRODUCTION AND DISPOSITION OF METHANOL, FOR CANADA,
1975-1995 (HIGH CASE)

consumption is uncertain. These factors make the task especially difficult. The relationships between energy demand, Gross National Product, prices, and population that have been observed and calculated during a period of lower and stable energy prices may change drastically in the future. The lack of historical data and experience in forecasting demand under such rapidly changing conditions is reflected in the wide variation in the demand forecasts submitted to the Board.

In the light of this uncertainty, the Board has prepared three forecasts of demand: high, medium and low. All three forecasts are based upon price assumption (b) of the Board's Notice of Hearing; that is, Btu price equivalence between oil and gas. The three forecasts are based on different expectations as to the extent that higher energy prices will affect economic activity, and different assumptions as to how great the effort to conserve energy will be. The assumptions as to the elasticity of total energy demand with respect to higher energy prices and the elasticity of the demand for gas with respect to the prices of gas and other fuels are necessarily a matter of judgment since a precise quantitative estimate cannot be reliably calculated at this time.

The three forecasts of demand are based on the expectation that the price of natural gas at the Toronto city gate will be phased into equivalence with crude oil on a Btu basis over a period of three years. Natural gas in Northern Ontario and the Prairie Provinces is expected to be priced lower than oil because of the higher costs of transporting natural gas compared with crude oil. Equivalence of gas and crude oil prices on a Btu basis has also been assumed for commercial and industrial use in British Columbia. However, natural gas prices at the burner-tip are expected to remain substantially below oil prices in the residential sector in British Columbia and in the residential and commercial sectors in Alberta as a result of provincial government policies.

The high forecast (Scenario I) assumes that higher energy prices will have little effect on economic activity and only a slight effect on total energy demand. Gross National Product is forecast to grow at five percent between 1977 and 1990. In this scenario the market share of gas is expected to increase to 1980 and remain relatively stable thereafter. The development of nuclear power and the greater use of coal in the industrial and thermal electric sectors, combined with the constant market share for gas, imply that the market share of oil will decline significantly throughout the forecast period. The average annual growth in natural gas sales resulting from these assumptions is 6.5 percent, producing an expected level of sales of 4,952 Bcf in 1995 compared with 1,229 Bcf in 1973.

In the medium forecast (Scenario II), higher energy prices are assumed to reduce economic activity and to induce conservation efforts. The growth in real GNP after 1980 is forecast to be 4.5 percent per annum in this scenario. The market share of gas is expected to increase to 1980 and then gradually fall off from this level, reflecting the greater use of coal and nuclear

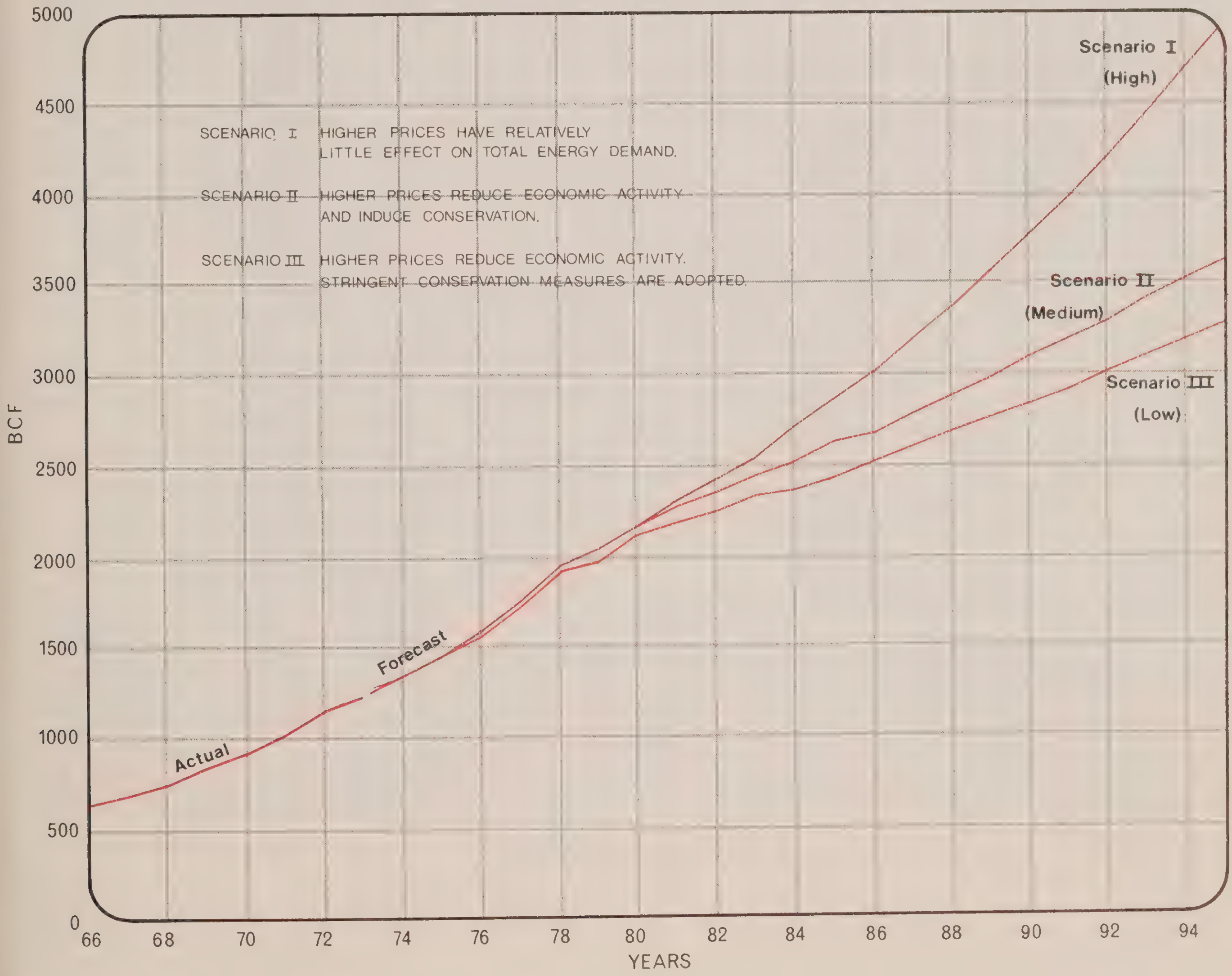
power in the latter part of the forecast period. A sector by sector, province by province forecast for Scenario II is shown in Tables 6 to 12. The growth in natural gas sales in this case averages 8.5 percent a year over the period 1974 to 1980 and 3.5 percent between 1980 and 1995 resulting in an average annual growth rate for the entire forecast period of 4.9 percent, and a level of sales at the end of the forecast period of 3,634 Bcf.

Scenario III illustrates the effect on gas sales if stringent conservation measures are adopted. It assumes that increased energy prices will reduce GNP growth to 4.5 percent a year after 1980. The combination of low economic growth and severe conservation measures results in a growth in gas sales of 3.0 percent a year in the period 1980 to 1995, with a level of sales of 3,293 Bcf in the final year of the forecast period.

The projected net sales for gas under the three scenarios is shown in Figure 8 and Table 1. The forecasts of compressor fuel requirements, transmission losses, and reprocessing shrinkage under Scenario II are shown in Table 3.

The total residential, commercial, industrial, petrochemical and thermal generation demand by province for the period 1973-1995 for Scenario II is summarized in the following table. A forecast of potential demand in the Atlantic provinces

Figure 8
NEB FORECAST OF NATURAL GAS NET SALES, CANADA, 1966-1995 (PRICE ASSUMPTION B)
(Table 1)



TOTAL NET SALES OF NATURAL GAS 1973-1995 SCENARIO II

(Medium Case)

(Bcf)

	1973	1975	1980	1985	1990	1995
British Columbia	150	175	231	320	396	478
Alberta	281	328	547	635	702	795
Saskatchewan	93	102	130	150	177	200
Manitoba	62	69	80	92	105	120
Ontario	579	714	1,010	1,165	1,379	1,639
Quebec	64	95	177	261	331	402
CANADA	1,229	1,483	2,175	2,623	3,090	3,634

April, 1975

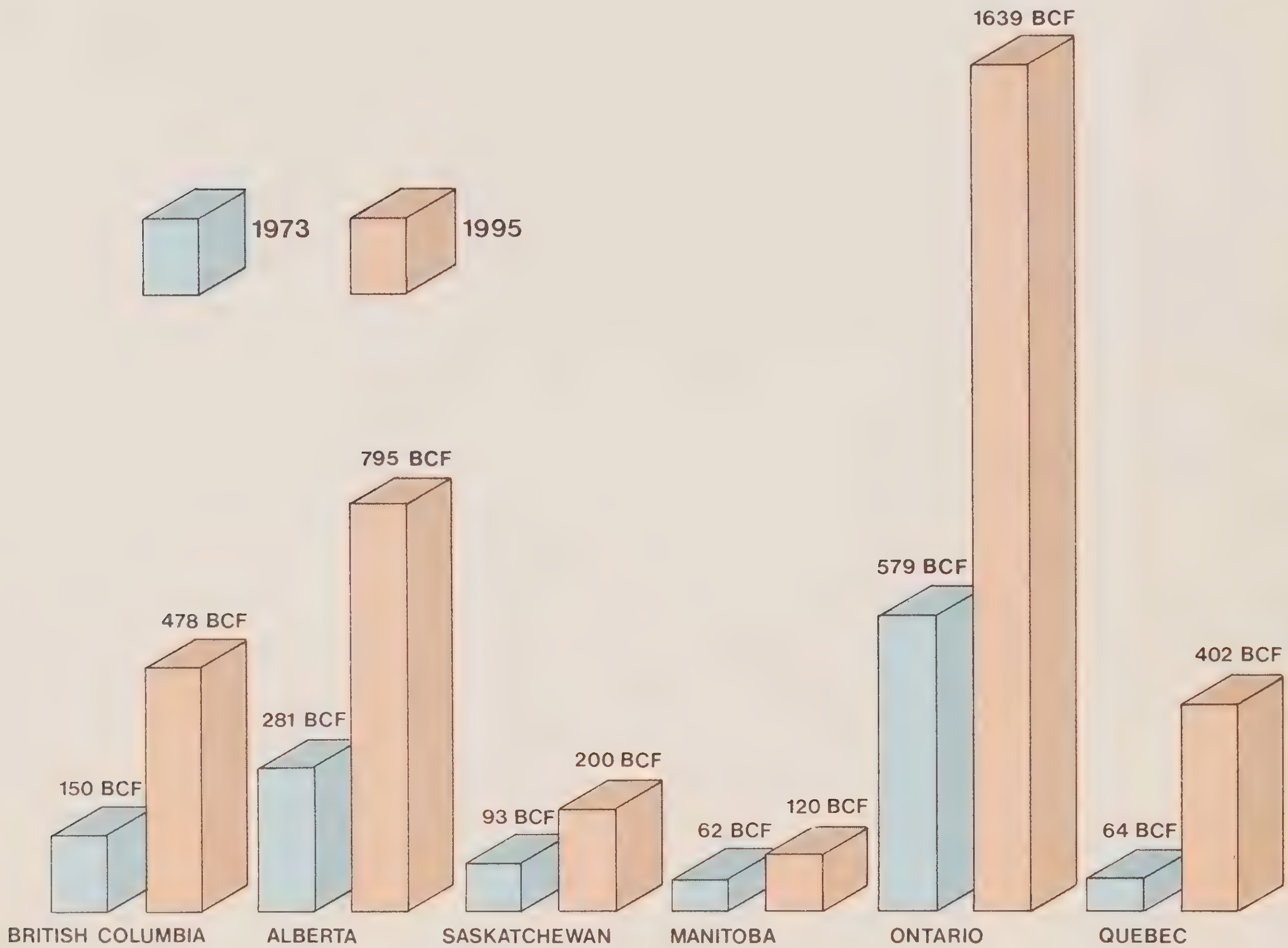


Figure 9

NEB FORECAST OF NET SALES OF NATURAL GAS BY PROVINCE
1973-1995 (SCENARIO II)
(Table 6, 8, 9, 10, 11, 12)

has been excluded from this report as the demand in this area will depend on the availability of gas from new East Coast Offshore sources.

The growth in demand by province between 1973 and 1995 is depicted graphically in Figure 9.

The total Canadian requirements by end-use sector are summarized in the following table.

The Canadian requirements for natural gas by sector are shown in Figure 10.

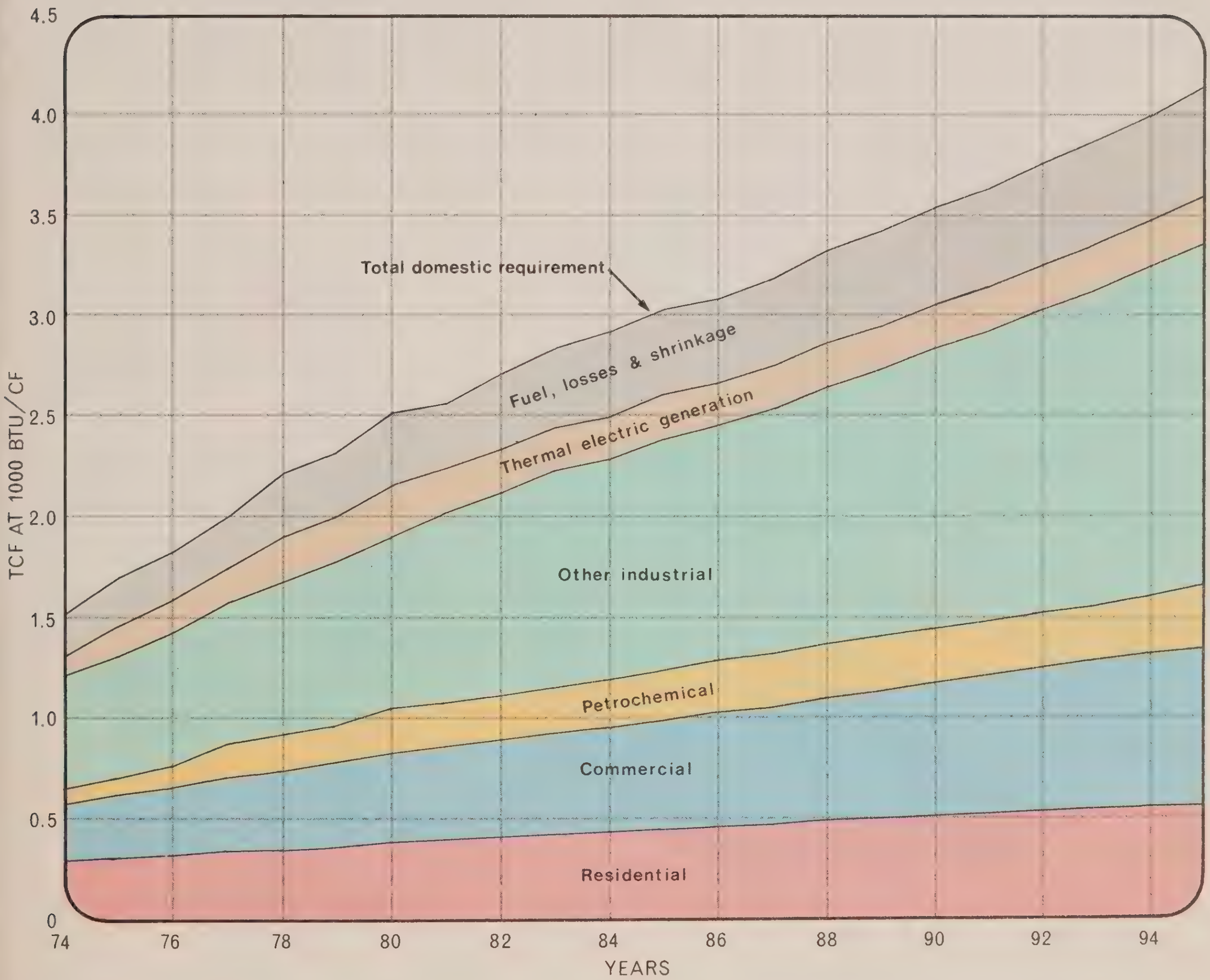


Figure 10

NEB FORECAST OF DOMESTIC REQUIREMENTS FOR NATURAL GAS BY SECTOR, CANADA
1973-1995 (SCENARIO II, MEDIUM CASE)
(Table 2)

TOTAL CANADIAN REQUIREMENTS FOR NATURAL GAS SCENARIO II

(Medium Case)

(Bcf)

	1973	1975	1980	1985	1990	1995
Residential	272	324	407	470	535	599
Commercial	246	314	442	549	668	797
Petrochemical	75	88	223	249	272	288
Other Industrial	491	606	870	1,136	1,388	1,712
Thermal Generation	145	151	233	219	228	238
Total Net Sales	1,229	1,483	2,175	2,623	3,090	3,634
Fuel & Losses for Domestic Use	115	142	235	298	347	403
Reprocessing Shrinkage	79	89	113	126	131	133
Total Domestic Demand	1,423	1,714	2,523	3,047	3,568	4,170

April, 1975

The Scenario II forecast implies a shift in gas demand for the various end-use sectors. Residential and thermal power demand are expected to take a small share of the total demand for natural gas while increases are foreseen for the commercial petrochemical and other industrial demand sectors. This is illustrated in Figure 11.

It should be noted that these forecasts of demand under the three different scenarios are forecasts of potential demand; that is, no constraints on the supply of natural gas were assumed.

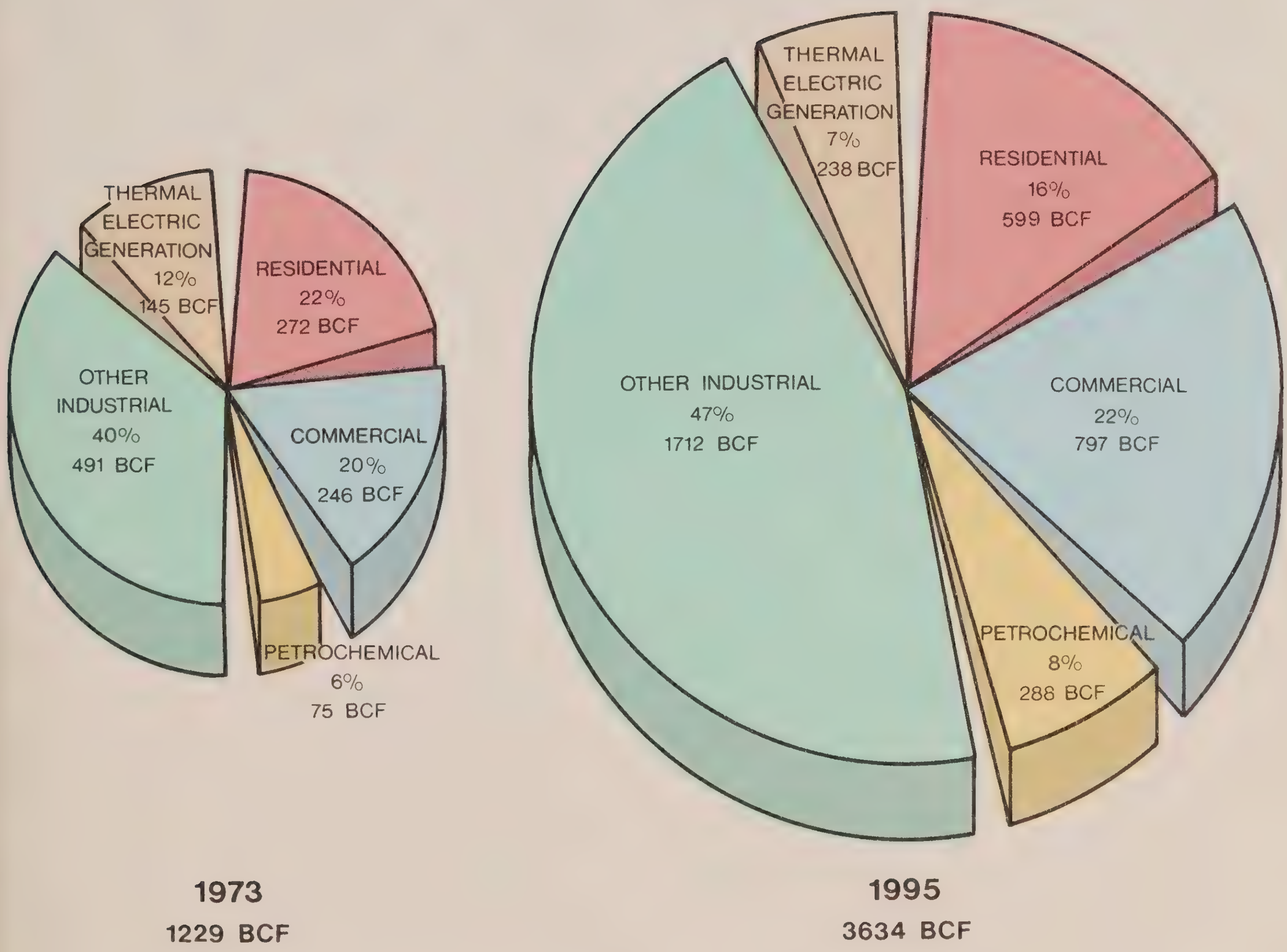


Figure 11
NEB FORECAST OF NATURAL GAS SALES BY END-USE SECTOR
1973 and 1995 (SCENARIO II)
(Table 2)

NEB FORECAST OF NATURAL GAS NET SALES IN CANADA
1973-1995

Price Assumption B
(Bcf at 1000 Btu/cf)

Year	Total Net Sales		
	Scenario I (High Case)	Scenario II (Medium Case)	Scenario III (Low Case)
1973	1229	1229	1229
74	1329	1329	1329
75	1483	1483	1483
76	1599	1599	1583
77	1762	1762	1737
78	1936	1936	1902
79	2041	2041	1997
80	2175	2175	2120
81	2298	2285	2183
82	2428	2359	2248
83	2565	2432	2315
84	2709	2518	2384
85	2862	2623	2455
86	3023	2687	2528
87	3193	2781	2603
88	3373	2877	2681
89	3563	2973	2761
90	3764	3090	2843
91	3977	3191	2928
92	4201	3299	3015
93	4438	3406	3105
94	4688	3517	3198
95	4952	3634	3293

NOTE: Excludes fuel, losses and reprocessing shrinkage

April, 1975

TABLE 2

NEB FORECAST OF DEMAND FOR NATURAL GAS, CANADA, 1973-1995

Scenario II (Medium Case)
(Bcf at 1000 Btu/cf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales*	Fuel, Losses, Shrinkage**	Total Domestic Requirement**
1973	271.8	245.6	75.0	491.4	145.6	1229.4	194.1	1423.5
74	304.1	285.6	76.3	552.8	110.6	1329.4	209.5	1538.9
75	323.5	314.0	87.7	605.9	151.5	1482.6	231.8	1714.4
76	342.4	343.7	103.2	655.6	154.1	1599.0	246.6	1845.6
77	361.1	372.9	166.1	704.2	157.9	1762.2	263.6	2025.8
78	377.7	399.3	181.9	752.1	225.2	1936.2	306.6	2242.8
79	392.1	421.7	184.9	813.3	228.8	2040.8	329.2	2370.0
80	406.5	441.6	223.3	870.3	233.3	2175.0	347.5	2522.5
81	419.0	462.5	225.2	942.4	235.8	2284.9	365.8	2650.7
82	431.8	482.9	227.2	989.4	227.7	2359.0	388.7	2747.7
83	444.6	504.4	229.3	1036.9	216.8	2432.0	398.8	2830.8
84	457.5	526.6	231.5	1084.8	217.8	2518.2	411.2	2929.4
85	470.2	549.2	249.0	1135.6	218.7	2622.8	423.8	3046.6
86	483.6	572.0	250.8	1161.0	219.2	2686.6	429.8	3116.4
87	496.8	594.8	252.7	1216.0	220.2	2780.5	443.1	3223.6
88	509.6	618.6	254.7	1273.0	221.3	2877.2	456.8	3334.0
89	521.8	642.7	256.7	1329.6	222.4	2973.2	470.5	3443.7
90	534.6	667.8	271.9	1387.6	227.9	3089.8	478.0	3567.8
91	546.6	692.4	274.2	1449.6	228.1	3190.9	487.9	3678.8
92	560.1	717.2	276.6	1511.3	234.2	3299.4	500.1	3799.5
93	572.5	742.5	279.0	1576.8	235.2	3406.0	512.0	3918.0
94	585.1	768.9	281.5	1644.3	236.7	3516.5	520.2	4036.7
95	598.6	796.8	287.6	1712.5	238.2	3633.7	536.6	4170.3

Note: * Excludes Atlantic Provinces
** Excludes fuel used in Canada for transporting exports; includes fuel used in U.S.A. to transport gas for Canadian consumption

April, 1975

NEB FORECAST OF CANADIAN NATURAL GAS REQUIREMENTS 1973-1995

Scénario II (Medium Case)
(Bcf at 1000 Btu/cf)

Year	Total Net Sales	Fuel & Losses For Domestic Use		Reprocessing Shrinkage	Total Requirement	Fuel for Exports In Canada
		In Canada	in U.S.A.			
1973	1229	99	17	79	1424	46
74	1329	108	19	83	1539	44
75	1483	121	21	89	1714	48
76	1599	130	23	94	1846	48
77	1762	140	25	99	2026	47
78	1936	172	28	107	2243	47
79	2041	190	29	110	2370	47
80	2175	204	31	113	2523	45
81	2285	220	32	114	2651	43
82	2359	239	33	117	2748	42
83	2432	245	34	120	2831	41
84	2518	252	36	123	2929	41
85	2623	261	37	126	3047	41
86	2687	268	38	123	3116	39
87	2781	276	40	127	3224	35
88	2877	285	41	131	3334	34
89	2973	294	43	134	3444	31
90	3090	302	45	131	3568	11
91	3191	312	46	130	3679	7
92	3299	321	48	131	3799	3
93	3406	331	49	132	3918	2
94	3517	340	51	129	4037	1
95	3634	350	53	133	4170	1

April, 1975

ESTIMATES OF NATURAL GAS REQUIREMENTS FOR PETROCHEMICAL PRODUCTION IN CANADA 1974-1995

(Bcf)

Year	D.W. Ross and Associates Ltd.	Canadian Petroleum Association	Canadian Arctic Gas Study Limited	Imperial Oil Limited	Shell Canada Limited
1974	86.3	86.4	76	76.3*	87
75	91.4	97.4	110	87	94
76	134.8	129.5	110	98	116
77	152.9	191.9	159	169	177
78	155.4	264.5	169	220	212
79	197.4	303.1	179	240	212
80	226.7	338.9	236	242	237
81	248.9	357.0	236	250	239
82	280.4	381.0	256	279	262
83	314.2	403.2	278	301	263
84	318.2	406.8	285	328	265
85	346.5	425.1	293	336	266
86	354.0	428.5	300	336	268
87	360.1	433.7	306	336	269
88	366.5	441.3	333	350	271
89	373.1	446.4	340	355	272
90	381.4	466.3	347	355	274
91	388.1	471.9	354	355	275
92	394.9	478.3	381	369	277
93	401.8	484.5	389	375	279
94	409.2	491.5	397	375	280
95	448.0	498.4	405	375	282

* Supplied by NEB

April, 1975

NEB FORECAST OF NATURAL GAS REQUIREMENTS FOR PETROCHEMICAL PRODUCTION BY PROVINCE AND FOR TOTAL CANADA, 1974-1995

(Bcf)

Year	ALBERTA			ONTARIO			BRITISH COLUMBIA			MANITOBA			TOTAL CANADA		
	Existing	New	Total	Existing	New	Total	Existing	New	Total	Existing	New	Total	Existing	New	Total
1974	43.0	1.3	44.3	24		24.0	4.5	—	4.5	3.5		3.5	75.0	1.3	76.3
75	43.0	12.7	55.7	24		24.0	4.5	—	4.5	3.5	–	3.5	75.0	12.7	87.7
76	43.0	28.2	71.2	24		24.0	4.5	—	4.5	3.5		3.5	75.0	28.2	103.2
77	43.0	91.1	134.1	24		24.0	4.5	—	4.5	3.5		3.5	75.0	91.1	166.1
78	43.0	106.9	149.9	24	—	24.0	4.5	–	4.5	3.5		3.5	75.0	106.9	181.9
79	43.0	106.9	149.9	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	109.9	184.9
80	43.0	145.3	188.3	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	148.3	223.3
81	43.0	147.2	190.2	24	3	27.0	4.5	—	4.5	3.5	–	3.5	75.0	150.2	225.2
82	43.0	149.2	192.2	24	3	27.0	4.5	—	4.5	3.5	–	3.5	75.0	152.2	227.2
83	43.0	151.3	194.3	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	154.3	229.3
84	43.0	153.5	196.5	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	156.5	231.5
85	43.0	171.0	214.0	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	174.0	249.0
86	43.0	172.8	215.8	24	3	27.0	4.5	—	4.5	3.5	-	3.5	75.0	175.8	250.8
87	43.0	174.7	217.7	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	177.7	252.7
88	43.0	176.7	219.7	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	179.7	254.7
89	43.0	178.7	221.7	24	3	27.0	4.5	—	4.5	3.5		3.5	75.0	181.7	256.7
90	43.0	192.9	235.9	24	4	28.0	4.5	—	4.5	3.5		3.5	75.0	196.9	271.9
91	43.0	195.2	238.2	24	4	28.0	4.5	–	4.5	3.5		3.5	75.0	199.2	274.2
92	43.0	197.6	240.6	24	4	28.0	4.5	—	4.5	3.5		3.5	75.0	201.6	276.6
93	43.0	200.0	243.0	24	4	28.0	4.5	—	4.5	3.5		3.5	75.0	204.0	279.0
94	43.0	202.5	245.5	24	4	28.0	4.5	-	4.5	3.5		3.5	75.0	206.5	281.5
95	43.0	208.6	251.6	24	4	28.0	4.5	—	4.5	3.5		3.5	75.0	212.6	287.6

April, 1975

TABL

NEB FORECAST OF DEMAND FOR NATURAL GAS, BRITISH COLUMBIA, 1973-1995

Scenario II (Medium Case)

(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	33.9	27.0	4.5	56.6	27.7	149.7
74	38.2	32.3	4.5	60.6	2.3	137.9
75	42.2	34.0	4.5	64.5	30.0	175.2
76	45.3	37.0	4.5	69.3	30.0	186.1
77	48.4	40.1	4.5	75.2	30.0	198.2
78	51.4	43.6	4.5	78.7	30.0	208.2
79	54.5	47.2	4.5	83.7	30.0	219.9
80	57.5	50.9	4.5	88.5	30.0	231.4
81	61.3	55.7	4.5	115.5	30.0	267.0
82	64.6	59.9	4.5	120.1	30.0	279.1
83	68.1	64.2	4.5	124.9	30.0	291.7
84	71.8	68.7	4.5	129.2	30.0	304.2
85	75.5	73.3	4.5	137.0	30.0	320.3
86	79.2	78.1	4.5	141.9	30.0	333.7
87	83.0	83.1	4.5	146.9	30.0	347.5
88	87.1	88.3	4.5	152.2	30.0	362.1
89	90.8	93.5	4.5	157.4	30.0	376.2
90	94.7	99.0	4.5	163.2	35.0	396.4
91	98.1	104.8	4.5	169.1	35.0	411.5
92	101.4	110.2	4.5	174.7	40.0	430.8
93	104.7	115.6	4.5	181.0	40.0	445.8
94	108.0	121.6	4.5	187.2	40.0	461.3
95	111.4	127.1	4.5	193.8	40.0	477.9

NOTE: Includes Vancouver Island

April, 1975

NEB FORECAST OF
DEMAND FOR NATURAL GAS, VANCOUVER ISLAND, 1973-1995

Scenario II (Medium Case)
(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	–	–				
74	–	–	–	–	–	–
75		–	–	–		
76	–	–	–	–	–	–
77	–		–			
78	–		–	–	–	–
79	–	–	–			
80	–	–		–	–	–
81	0.9	1.1		22.4		[illegible]
82	1.4	[illegible]		[illegible]		[illegible]
83	2.1	2.1	–	23.4	–	[illegible]
84	[illegible]	[illegible]	–	[illegible]		[illegible]
85	[illegible]	[illegible]	–	[illegible]		[illegible]
86	[illegible]	[illegible]	–	[illegible]		[illegible]
87	5.0	[illegible]	–	25.1	–	[illegible]
88	[illegible]	[illegible]		[illegible]		[illegible]
89	6.5	5.8		[illegible]		[illegible]
90	7.2	[illegible]	–	[illegible]		[illegible]
91	7.9	[illegible]		[illegible]		[illegible]
92	8.7	[illegible]		[illegible]		[illegible]
93	9.4	[illegible]		[illegible]		[illegible]
94	10.0	[illegible]	–	[illegible]	–	[illegible]
95	10.7	[illegible]		[illegible]		[illegible]

[illegible] 1977

NEB FORECAST OF DEMAND FOR NATURAL GAS, ALBERTA, 1973-1995

Scenario II (Medium Case)

(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	65.2	61.1	43.0	56.9	54.9	281.0
74	74.3	69.5	44.3	64.7	54.9	307.7
75	76.9	73.4	55.7	68.3	53.7	328.0
76	79.6	77.5	71.2	72.1	56.3	356.7
77	82.1	81.3	134.1	76.1	60.1	433.7
78	84.7	85.2	149.9	80.3	63.9	464.0
79	87.1	88.7	149.9	99.7	67.5	492.9
80	89.6	92.4	188.3	104.4	72.0	546.7
81	90.9	96.6	190.2	109.3	74.5	561.5
82	92.2	100.9	192.2	114.5	75.0	574.8
83	93.5	105.4	194.3	120.0	76.0	589.2
84	94.8	110.1	196.5	125.8	77.0	604.2
85	96.1	114.9	214.0	131.9	77.9	634.8
86	97.4	118.9	215.8	115.3	78.4	625.8
87	98.3	122.9	217.7	122.1	79.4	640.9
88	100.2	127.0	219.7	129.3	80.5	656.7
89	101.6	131.3	221.7	136.9	81.6	673.1
90	103.0	135.7	235.9	144.9	82.1	701.6
91	104.4	139.1	238.2	153.3	82.3	717.3
92	105.9	142.5	240.6	162.2	83.4	734.6
93	107.4	146.0	243.0	171.6	84.4	752.4
94	108.9	149.6	245.5	181.5	85.9	771.4
95	110.4	153.3	251.6	191.9	87.4	794.6

April, 1975

TABL

NEB FORECAST OF DEMAND FOR NATURAL GAS, SASKATCHEWAN, 1973-1995

Scenario II (Medium Case)

(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
74	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
75	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
76	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
77	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
78	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
79	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
80	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
81	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
82	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
83	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
84	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
85	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
86	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
87	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
88	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
89	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
90	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
91	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
92	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
93	[illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]
94	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
95	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

NEB FORECAST OF DEMAND FOR NATURAL GAS, MANITOBA, 1973-1995

Scenario II (Medium Case)

(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	21.3	17.5	3.5	17.0	3.1	62.4
74	25.3	20.4	3.5	14.4	3.1	66.7
75	25.8	20.9	3.5	[illegible]	1.0	68.7
76	26.3	21.4	3.5	18.4	1.0	70.6
77	27.0	22.0	3.5	19.3	1.0	72.8
78	27.7	22.6	3.5	[illegible]	1.0	75.1
79	28.5	23.3	3.5	21.3	1.0	77.6
80	29.2	24.0	3.5	[illegible]	1.0	80.1
81	29.8	24.5	3.5	23.4	1.0	82.2
82	30.4	25.0	3.5	24.5	1.0	84.4
83	31.1	25.6	3.5	25.6	1.0	86.8
84	31.7	26.1	3.5	26.8	1.0	89.1
85	32.4	26.7	3.5	28.0	1.0	91.6
86	33.0	27.3	3.5	[illegible]	1.0	94.1
87	33.7	27.9	3.5	30.6	1.0	96.7
88	34.4	28.5	3.5	[illegible]	1.0	99.4
89	35.1	29.1	3.5	[illegible]	1.0	102.1
90	35.8	29.7	3.5	34.9	1.0	104.9
91	36.5	30.3	3.5	36.5	1.0	107.8
92	37.2	31.0	3.5	[illegible]	1.0	110.8
93	37.8	31.6	3.5	39.8	1.0	113.7
94	38.5	32.2	3.5	[illegible]	1.0	116.8
95	39.2	32.9	3.5	43.5	1.0	120.1

April, 1975

NEB FORECAST OF
DEMAND FOR NATURAL GAS, ONTARIO, 1973-1995

Scenario II (Medium Case)
(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	111.9	117.5	24.0	285.2	41.0	579.1
74	125.0	133.7	24.0	318.1	41.6	646.8
75	135.0	159.5	24.0	343.5	51.8	713.8
76	145.8	180.2	24.0	367.5	51.8	769.3
77	156.0	200.0	24.0	393.2	51.8	825.0
78	163.8	216.5	24.0	416.3	115.5	935.9
79	168.7	[illegible]	27.0	[illegible]	[illegible]	975.4
80	173.8	234.7	27.0	459.5	115.3	1010.3
81	177.3	[illegible]	27.0	470.2	115.3	1042.7
82	180.8	251.3	27.0	501.3	106.7	1067.7
83	184.4	260.2	27.0	524.4	94.8	1090.8
84	188.1	[illegible]	27.0	[illegible]	[illegible]	1127.2
85	191.9	[illegible]	27.0	572.7	[illegible]	1165.1
86	195.7	[illegible]	27.0	[illegible]	94.8	1204.5
87	199.6	[illegible]	27.0	[illegible]	[illegible]	1245.4
88	203.6	309.1	27.0	653.5	94.8	1288.0
89	207.7	319.9	27.0	682.9	94.8	1332.3
90	211.9	331.1	[illegible]	713.6	94.8	1379.4
91	216.1	342.7	[illegible]	745.7	94.8	1427.3
92	220.4	[illegible]	[illegible]	779.3	94.8	1477.2
93	224.8	367.1	[illegible]	811.4	94.8	1529.1
94	229.3	379.9	[illegible]	851.0	94.8	1583.0
95	233.9	393.2	[illegible]	889.2	94.8	1639.2

April, 1975

NEB FORECAST OF DEMAND FOR NATURAL GAS, QUEBEC, 1973-1995

Scenario II (Medium Case)

(Bcf)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation	Total Net Sales
1973	15.8	9.3	–	39.1	–	64.2
74	17.0	10.0	–	53.0	–	80.0
75	18.0	11.0	–	66.0	–	95.0
76	19.0	12.0	–	75.0	–	106.0
77	20.5	13.5	–	85.0	–	119.0
78	22.5	15.5		97.0	–	135.0
79	25.0	19.0	–	109.0	–	153.0
80	27.5	22.5	–	127.0	–	177.0
81	30.5	25.5	–	142.0	–	198.0
82	34.0	28.0	–	152.0	–	214.0
83	37.0	31.0		162.0	–	230.0
84	40.0	34.0	–	172.0	–	246.0
85	43.0	37.0	–	181.0		261.0
86	46.0	40.0	–	189.0		275.0
87	49.0	43.0	–	197.0	–	289.0
88	51.0	46.0		206.0	–	303.0
89	53.0	49.0	–	215.0		317.0
90	55.0	52.0	–	224.0	–	331.0
91	57.0	55.0	–	233.0	–	345.0
92	60.0	58.0	–	242.0		360.0
93	62.0	61.0	–	251.0	–	374.0
94	64.0	64.0		260.0		388.0
95	66.0	67.0	–	269.0		402.0

April, 1975

CANADIAN SUPPLY–RESERVES

INTRODUCTION

The determination of natural gas reserves is possible only through a pool by pool analysis of basic geological and engineering data. Since there are some 2,000 individual gas pools in Canada, the assessment of total reserves is a task which can be accomplished only by organizations with adequate staff to handle the vast quantity of basic data involved. It is probably for this reason that submittors to this Hearing based their reserves estimates to a considerable extent on those published by provincial governments and by the CPA, and deviated from these only for specific pools for which they had undertaken calculations of reserves, usually because of ownership interest.

Geological and engineering factors used in the calculation of reserves lend themselves to a degree of interpretation which is reflected in differences in estimates depending on the authority. A realistic appraisal of reserves recognizes that such differences are to be expected as a result of the element of professional judgment involved.

The Board notes some criticism directed to it concerning over-dependence on reserves estimates from industry sources. In actual fact, the Board maintains a staff of professional engineers and geologists whose primary responsibility it is to make independent evaluations of hydrocarbon reserves on a pool-by-pool basis.

The Board in this report continues its practice of identifying the volume of reserves in Canada estimated to be available as "established gas reserves".

CONVENTIONAL PRODUCING AREAS

a) ESTABLISHED RESERVES

(i) *Views of Submittors*

Submissions which include data on reserves came largely from operating companies, CPA, and provincial agencies. In these submissions reserves are variously described as proved, established, or simply as reserves, so that direct comparison is subject to error. Because of the considerable degree of judgment involved in their determination, however, for practical purposes such comparison may be made.

Estimates submitted of remaining reserves in the conventional producing areas as of December 31st, 1973 vary from 54.7 Tcf, the CPA "proved" volume,

Exploratory well being drilled in tundra, west of Inuvik

to 65.6 Tcf presented by TransCanada. Six of the eight estimates for all areas are between 60.6 Tcf and 63.3 Tcf.

Most submittors presented remaining reserves estimates only. When this was the case, corresponding initial reserves were calculated by adding cumulative production to December 31st, 1973, to provide the reserves datum for Figure 12 which illustrates growth of initial marketable reserves in the conventional producing areas as forecast by the submittors. Both initial and remaining reserves in the conventional producing areas have been standardized by the Board to a base of 1000 Btu/cf, to facilitate comparison of estimates.

Submittors' estimates of remaining reserves in the conventional producing areas are summarized in Table 13. For comparison the Board's established estimates are also shown.

(ii) *Views of the Board*

So far as could be determined, submittors who presented reserves data based on their own calculations followed accepted practices and established procedures applicable to reservoir evaluation.

The Board notes that while reserves estimates submitted cover a range of some 20 percent, six of the eight estimates for all areas, those between 60.6 Tcf and 62.3 Tcf vary considerably less than 10 percent. A 10 percent range is considered well within acceptable limits since it is due to the judgmental factors involved in the science of reserves estimation. The professional staff of the Board, in performing independent reserve calculations from basic reservoir data, has itself found variations of this magnitude not uncommon. The Board's estimate of remaining established reserves, 60.6 Tcf, is based on detailed evaluation of specific pools containing 70 percent of the reserves in Western Canada together with a more general treatment of other reserves.

The Board's estimate for British Columbia of 6.6 Tcf, which is less than that presented by any submittor, is based upon a careful evaluation and interpretation of all the evidence available for pools in this province. The Board has reduced its estimate of initial established reserves for the Beaver River field from 1,070 Bcf to 430 Bcf, and that for the Clarke Lake field from 2,070 Bcf to 1,050 Bcf, because of revised predictions of performance.

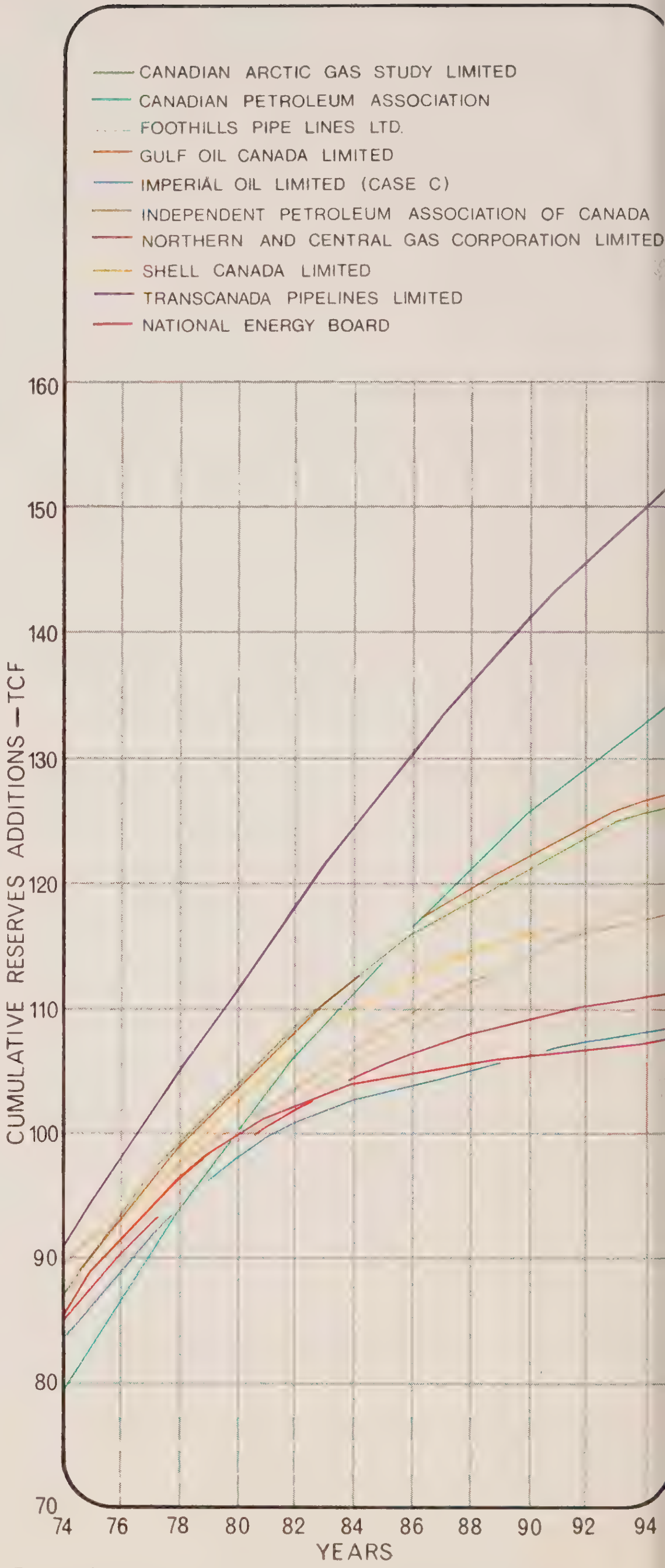


Figure 12

FORECAST GROWTH OF INITIAL MARKETABLE RESERVE (CONVENTIONAL PRODUCING AREA)

The Board also has reduced its estimate for the Northwest Territories, reflecting a decrease of 310 Bcf in the reserves ascribed to the Pointed Mountain field.

b) RESERVES ADDITIONS AND ULTIMATE POTENTIAL

(i) *Views of the Submittors*

Forecasts of reserves additions for the conventional producing areas from 1974-1995 were provided by several submittors. The volumes forecast range from 26.8 Tcf to 66.0 Tcf. Estimates of the ultimate reserves potential similarly cover a substantial range from 103 Tcf to 178 Tcf. If, however, the CPA high forecast of 178 Tcf is eliminated from consideration, the range narrows substantially, with an upper limit of 139 Tcf.

In some cases no forecast was included for Eastern Canada, but since the reserves in this region are small by comparison, totals are not affected significantly.

The procedures and methodologies employed by the various submittors in forecasting reserves additions were commonly based on consideration of historical finding rates, together with a judgmental assessment of the extent to which these rates might be different in the future. Play evaluation techniques were utilized by some submittors.

Submittors' forecasts of reserves additions in the conventional producing areas together with the Board forecast are shown in Table 14; Table 15 compares estimates of ultimate potential.

(ii) *Views of the Board*

The wide variation in forecasts submitted illustrates a considerable diversity of informed opinion as to how much gas will be found in the conventional producing areas.

The Board appreciates the very substantial judgmental factor that enters into any forecast of reserves additions or ultimate potential. However, it has difficulty in accepting future growth trends that differ materially from those established in the past, although it recognizes that projection of historical data may yield excessively conservative results because of the decline in rate of discovery in recent years.

The Board's analysis of the exploration maturity of the conventional producing areas leads to the conclusion that in all probability considerably more than 50 percent of the reserves have been discovered, and this percentage may be closer to 75 percent. At the same time, it can be argued that recent exploration experience is not truly representative of ultimate potential, and discovery rates are capable of considerable improvement. The Alberta and British Columbia foothills belt for example has been cited by submittors as a high potential region where exploration activity has been low because historically gas prices have not been able to support the high costs of operations.

The Board considers an ultimate potential of 115 Tcf reasonable, and has used this volume as the basis for its conclusion that some 25 Tcf may be added to present reserves within the next two decades. This conclusion assumes that some 80 percent of the gas remaining to be found will be developed by the end of this period.

It seems evident to the Board that a strong exploratory effort in the conventional producing areas is needed for its predicted additions of 25 Tcf to materialize. Indeed these additions are unlikely to result unless exploration is accelerated, particularly in the higher cost foothills belt and adjacent deep plains region of Alberta and British Columbia. For this reason, the Board finds highly disturbing the present trend of reduction in exploratory activity.

Figure 12 illustrates growth of initial marketable reserves in the conventional producing areas resulting from additions forecasts by submittors and by the Board.

FRONTIER REGIONS

a) RESERVES DISCOVERED

(i) *Views of Submittors*

Natural gas has been discovered in significant quantities in three separate Frontier regions, the Beaufort-Mackenzie Basin, the Arctic Islands, and the East Coast Offshore continental shelf.

Estimates of volumes found are summarized in Table 16. Submittors emphasize that because of the still largely confidential status of reservoir data at this time, their estimates are based to a considerable degree on public statements and documentation originating from the operators of pools discovered.

Estimates of reserves discovered in the Beaufort-Mackenzie Basin range from 4.0 Tcf to 7.3 Tcf.

CPA shows in its submission a "probable" reserve of 7.5 Tcf. At the Hearing CPA stated that it now estimates reserves of 4.0 Tcf proved and 4.8 probable for this area.

Estimates of reserves discovered to date in the Arctic Islands range from 8.5 to 12.5 Tcf.

Panarctic Oils Ltd., (Panarctic) which because of its participation in essentially all pools discovered in the Arctic Islands can be expected to have the most complete information of any submittor, describes its estimate of 12 Tcf as including proved, probable, and possible volumes. This suggests that reserves have been included to which a high confidence factor may not be applicable.

Three submissions carry estimates of reserves discovered thus far in East Coast Offshore waters. The estimates are nominal, from 0.4 Tcf to 1.0 Tcf.

(ii) *Views of the Board*

From evidence submitted, the Board has been made well aware of the difficulties involved in assessing at this time discovered reserves in the Frontier areas. It is quite clear that if a realistic current appraisal is to be made there must be consideration of the fact that in most cases inadequate development drilling has taken place for delineation of pool geometry. This factor, then, must be determined through interpretation of geophysical data. The resulting reserves estimates, while resting to a greater extent on interpretative data than estimates in pools delineated by drilling, should be regarded as "most likely" assessment at the time of appraisal.

b) ANTICIPATED ADDITIONS AND ULTIMATE POTENTIAL

(i) *Views of Submittors*

Submittors emphasized the uncertainty and speculative nature of estimates of anticipated additions in the Frontier regions, and their ultimate potential.

This is evidenced by the very substantial differences in estimates submitted. Anticipated additions range from 26 Tcf to 69 Tcf for the Beaufort-Mackenzie Basin, 39 Tcf to 84 Tcf for the Arctic Islands, and 3 Tcf to 42 Tcf for the East Coast Offshore areas. Submissions with respect to ultimate potential are limited in number; the uncertainties involved here are well expressed through the CPA high-low-average estimates of 573 Tcf, 193 Tcf and 370 Tcf respectively, for the Frontier regions in total.

Tables 17 and 18 show submittors' forecasts of reserves additions and ultimate potential estimates respectively, for the Beaufort-Mackenzie Basin, the Arctic Islands, and the East Coast Offshore areas.

(ii) *Views of the Board*

The Board agrees that the amount of undiscovered volumes of gas in the Frontier regions is highly speculative at this time.

While the Board is optimistic that large resources of natural gas may in fact exist, it cautions against equating these resources with reserves, and assuming that they can be made available with little effort whenever additional gas is needed. The accumulation of hydrocarbons is a relatively rare occurrence in nature; their discovery and development is a costly, uncertain and frequently frustrating task.

Although the results of exploration in the Frontier regions to date are encouraging, they can hardly be rated as spectacular. It is evident that an exploratory effort certainly no less vigorous than that undertaken by industry in recent years must be maintained if reserves additions even approaching the lower range of submittors' predictions are to be realized.

While continuing to be confident that significant reserves will be developed, the Board wishes to make it clear it will not recognize these reserves as available until there is an approved means of moving them to market.

Figures 13, 14, and 15 illustrates growth of initial marketable reserves in the Beaufort-Mackenzie Basin, Arctic Islands, and East Coast Offshore areas respectively, resulting from additions forecasts by submittors.

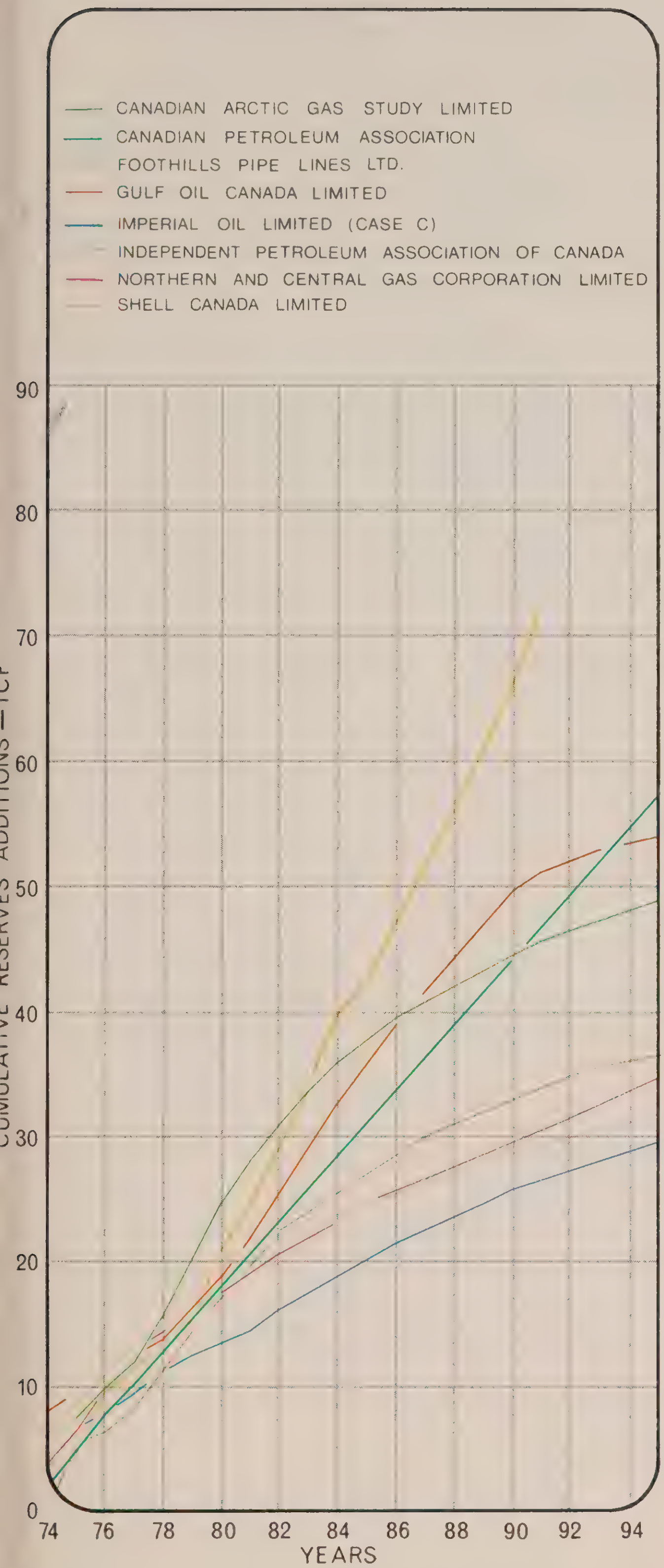


Figure 13
FORECAST GROWTH OF INITIAL MARKETABLE RESERVE OF NATURAL GAS (BEAUFORT – MACKENZIE BASIN)

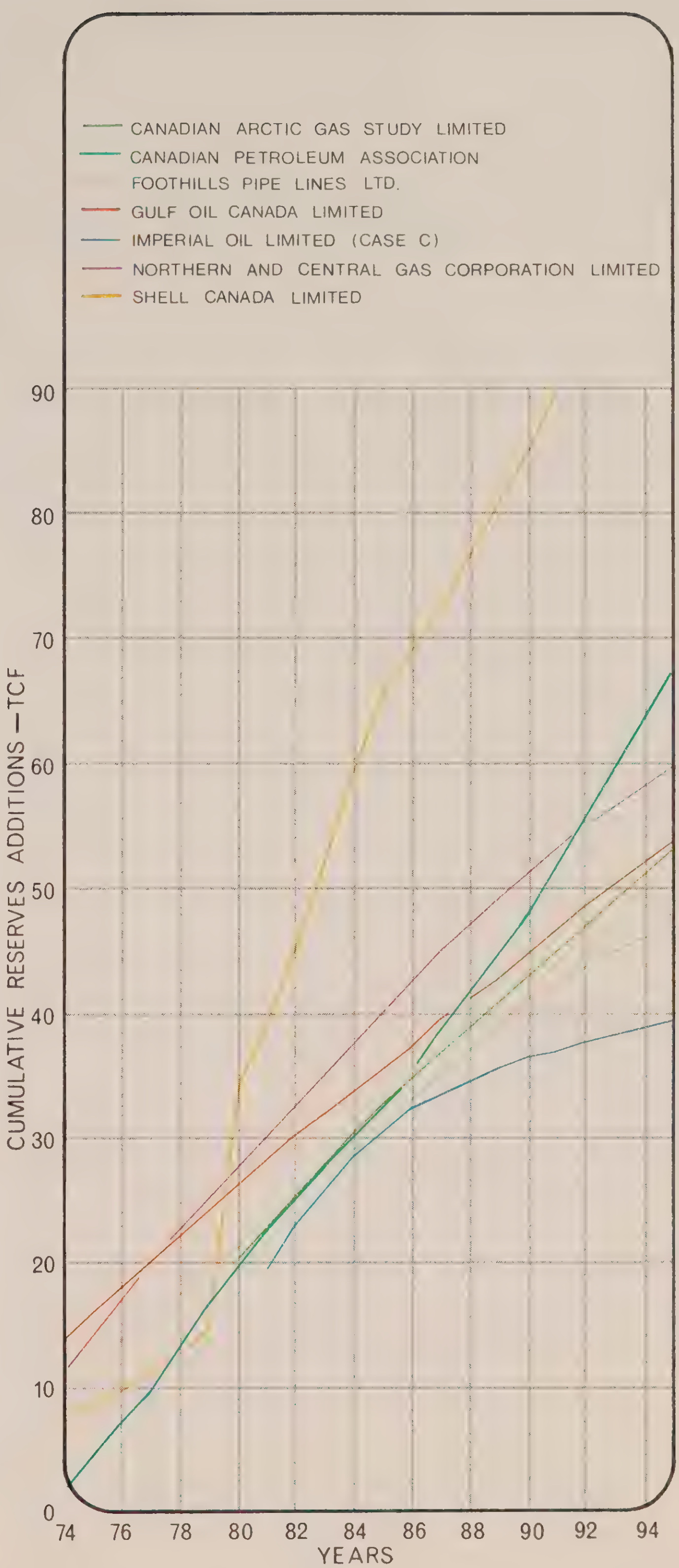


Figure 14
FORECAST GROWTH OF INITIAL RESERVES (ARCTIC ISLANDS)

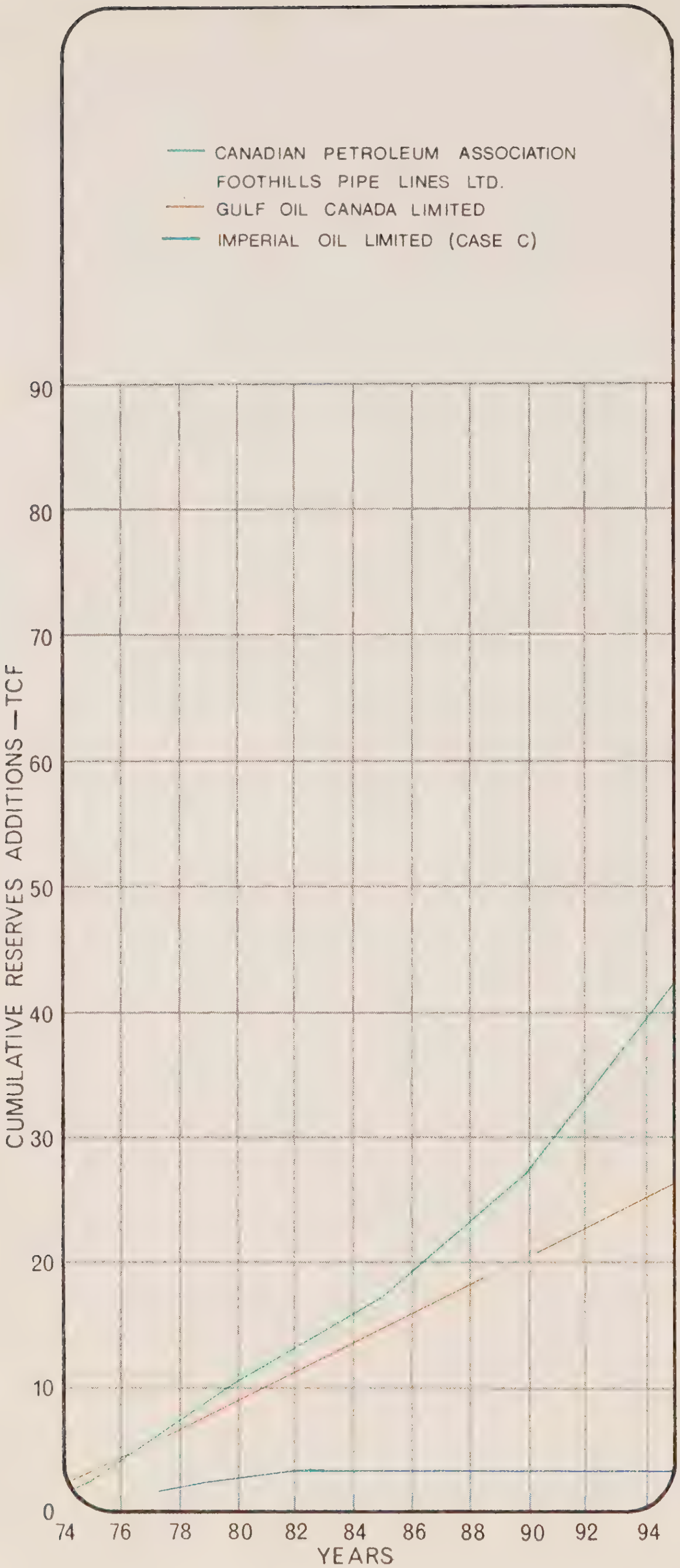


Figure 15

FORECAST GROWTH OF INITIAL RESERVES (EASTCOAST OFFSHORE)

SUPPLY ELASTICITY WITH RESPECT TO PRICE

(i) *Views of Submittors*

Most submittors presented their discussions of supply elasticity with respect to price in qualitative terms, assuming for the purpose of their reserves additions schedule that economic conditions will prevail to support vigorous, ongoing programs of both exploration and development.

CPA submitted forecasts of reserves additions under different pricing assumptions. For the conventional producing areas, these forecasts are very different. Imperial forecast additions from 1974 to 1995 of 23.9 Tcf under its case (a), continued underpricing. These are predicted to increase only slightly, to 25.9 Tcf and 26.8 Tcf respectively under case (b), price parity with crude oil, and case (c), commodity value. Sherman H. Clark Associates, (Sherman Clark) in sharp contrast, predicts minimum additions of 20.8 Tcf assuming no change in gas price in constant dollars, rising to 36.0 Tcf assuming a constant market price relative to oil, 51.0 Tcf with a market price equivalent to that of oil, and 66.0 Tcf if the price is allowed to reach true market value. It should be noted that the additions of 58 Tcf shown on Table 14 for CPA are those forecast by that agency, and are independent of the Sherman Clark data.

Imperial anticipates that under continued underpricing, no Frontier reserves would be developed. Price equivalence with crude oil would permit development of a part of the reserves believed to be available from the Beaufort-Mackenzie Basin, but commodity value would be required for full development, and for commercial exploitation of the Arctic Islands.

Sherman Clark's conclusions are very similar. Under constant relative prices with crude oil, it is most probable the net return to the producer in the Frontier areas would be close to zero. Only under price equivalence with crude oil, or a price reflecting parity value, could more than very limited development of these areas be anticipated.

(ii) *Views of the Board*

The Board considers it evident that without a system which will assure the explorer/producer adequate funds to pursue a vigorous program of exploration, reserves additions, both in the conventional producing and in the Frontier areas will fall far short even of the more conservative forecasts.

Price is not the sole consideration; it must be related to other economic factors such as royalty, tax schedules, and inflation, all of which affect netback to the producer.

From evidence submitted, explorer/producers commonly anticipate a discounted net cash flow rate of return after tax of 15 percent to 20 percent. Thus any expected return lower than this is likely to divert capital to more promising investments.

There seems to be little doubt that it is extremely difficult to forecast quantitatively the effect of price on supply. That the expectation of an improved rate of return will stimulate exploration is an acceptable thesis, but the results of an exploration program are always difficult to predict. The almost opposing views of Imperial and Sherman Clark with respect to the effect of price on reserves additions in the conventional producing areas illustrate this.

The Board finds it possible to draw only very general conclusions concerning the matter of supply elasticity with respect to price. It is virtually certain that as prices rise, providing a satisfactory rate of return is envisaged by the explorer/producer, a higher level of reserves additions will be attained. This will occur as the result both of accelerated activity in areas already explored to some degree, even those approaching maturity of development, and in new areas not previously considered economic. The relative increase in reserves additions in a given area as prices escalate should bear some relationship to the area's unrealized potential, so that quite spectacular increases may occur in some areas while only minor changes may result elsewhere. These conclusions underline the importance of a strong level of exploratory effort in the presently under-explored Frontier regions to determine at an early date the extent to which optimism with respect to their potential is justified.

REMAINING RESERVES OF MARKETABLE NATURAL GAS
CONVENTIONAL PRODUCING AREAS
31.12.73
(Tcf at 1000 Btu/cf)

	British Columbia Energy Commission	Canadian Arctic Gas Study Limited	Canadian Petroleum Association (proved)	Canadian Petroleum Association (probable)	Foothills Pipe Lines Ltd.	Gulf Oil Canada Limited	Imperial Oil Limited	Independent Petroleum Association of Canada	Northern and Central Gas Corporation Limited	Shell Canada Limited	TransCanada Pipelines Limited	Westcoast Transmission Company Limited	National Energy Board
British Columbia	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	–	[illegible]	[illegible]	[illegible]
[illegible]	–	[illegible]	[illegible]	[illegible]	[illegible]		–	[illegible]	[illegible]	–	[illegible]		51.6
[illegible]	–	[illegible]	[illegible]	[illegible]	[illegible]		–	[illegible]	[illegible]	–	[illegible]		1.1
Southern Territories	–	[illegible]	[illegible]	[illegible]	[illegible]		–	[illegible]	[illegible]		1.4	0.9[3]	1.0
Western Canada Total	–	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]		[illegible]		60.[illegible]
Ontario and other Eastern Canada	–	[illegible]	[illegible]	[illegible]	[illegible]		–		[illegible]		[illegible]		0.3
Canada Total		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]	63.0	65.6		[illegible]

NOTE: Totals may not add to rounding.
Converted to volumes at 1000 BTU/cf when not so reported.
1) mid-year 1974 estimate of British Columbia Department of Mines and Petroleum Resources.
2) Energy Resources Conservation Board estimate for Alberta; Canadian Petroleum Association proved estimates for other areas.
3) revised estimate of December 31, 1974.

April, 1975

TABLE

MARKETABLE NATURAL GAS RESERVES ADDITIONS FORECASTS CONVENTIONAL PRODUCING AREAS

1974-1995

(Tcf)

	British Columbia Energy Commission	Canadian Arctic Gas Study Limited	Canadian Petroleum Association	Sherman H. Clark Associates	Foothills Pipe Lines Ltd.	Gulf Oil Canada Limited	Imperial Oil Limited	Mobil Oil Canada, Ltd.6)	Northern and Central Gas Corporation Limited	Shell Canada Limited	TransCanada Pipelines Limited	Union Gas Limited	Westcoast Transmission Company Limited	Independent Petroleum Association of Canada	National Energy Board
British Columbia	10.7 1)	6.9	9.3	–	4.9	6.3 3)	-	-	7.3	-	13.2	–	10.1 11)	-	5
Alberta	-	34.8	38.3	-	24.7	35.1	-	40.7 7)	19.6	–	48.1	21	–		17
Saskatchewan	–	–	1.0	–	0.7	0.9 4)	-	0.8 8)	1.7	–	2.7 10)		–	–	1
Southern Territories	–	–	9.5	–	3.4	–	-	–	–	-	–	–	–	–	2
Western Canada Total	–		58.1	66.0 2)	33.7	–	26.8 5)	–	–	–		–		30.6 12)	25
Ontario and other Eastern Canada	–		-		1.1	–	–	–	–	–	-	-	–	–	-
Canada Total	–	-	–		34.8	42.3		41.5		31.3 9)	64.0	–	–	-	25

NOTE:

1) case 1 discovery rate 250 Bcf/year
2) assumption D — parity price
3) includes southern Territories
4) includes all conventional producing areas except Alberta, British Columbia and southern Territories
5) case (c) — commodity value
6) 1975-1995
7) includes British Columbia and the Yukon portion of the Liard Basin
8) includes Ontario
9) 1974-1991
10) includes all conventional producing areas except Alberta and British Columbia
11) Westcoast supply area; British Columbia, southern Territories and northwestern Alberta.
12) Western Provinces only

avril, 1975

ULTIMATE POTENTIAL ESTIMATES CONVENTIONAL PRODUCING AREAS

(Tcf)

	Canadian Petroleum Association 1)	Foothills Pipe Lines Ltd.	Gulf Oil Canada Limited	Imperial Oil Limited	Northern and Central Gas Corporation Limited	John P. Strong	National Energy Board
British Columbia	32-17-24	17.0	20 2)	16	20-25	21-24 4)	15
Alberta	125-79-98	99.5	111	—	90	82-100	92
Saskatchewan	3-2-3	3.3	4 3)	—	—	—	3
Southern Territories	18-10-14	7.1	—	—	—	—	4
Western Canada Total	178-108-139	126.9	—	118	—	—	114
Ontario and other Eastern Canada	—	[illegible]				—	1
Canada Total	—	[illegible]	[illegible]	—	—	[illegible]	115

April, 1975

NOTE:

1) high-low-average estimates.
2) includes southern Territories.
3) includes all conventional producing areas except Alberta, British Columbia and southern Territories.
4) includes all conventional producing areas except Alberta.

ESTIMATES OF NATURAL GAS DISCOVERED FRONTIER AREAS

31-12-73

(Tcf)

	Canadian Petroleum Association (probable)	Foothills Pipe Lines Ltd.	Gulf Oil Canada Limited	Independent Petroleum Association of Canada	Northern and Central Gas Corporation Limited	Panarctic Oils Ltd.	Shell Canada Limited
Beaufort-Mackenzie Basin	4.8[1]	6.2	7.0	5.0	4.0		7.3[2]
Arctic Islands	12.0[2]	8.5	12.0	-	10.0	12.0	12.5[3]
East Coast Offshore	1.0[2]	0.1	1.0			-	-
Other Frontier Areas			0.4	-	-	-	-

NOTE:

1) revised estimate 31-12-74; original estimate 7.5 TCF
2) this volume also included in additions forecast
3) 50% of this volume included in additions forecast

April, 1975

NATURAL GAS RESERVES ADDITIONS FORECASTS
FRONTIER AREAS
1974-1995
(Tcf)

	Canadian Arctic Gas Study Limited1)	Canadian Petroleum Association	Foothills Pipe Lines Ltd.	Gulf Oil Canada Limited	Imperial Oil Limited1,3)	Independent Petroleum Association of Canada	Mobil Oil Canada, Ltd.5)	Northern and Central Gas Corporation Limited	Shell Canada Limited7,8)
Beaufort-Mackenzie Basin	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Arctic Islands	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]
East Coast Offshore		[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	–	–
Other Frontier Areas		[illegible]	[illegible]	[illegible]	[illegible]				–

NOTE:
1) includes volume discovered to date
2) includes all Territories mainland
3) case (c) — commodity value
4) Grand Banks, Scotian Shelf and Gulf of St. Lawrence only
5) 1975-1995
6) includes all Territories mainland except the Liard Basin
7) includes half of volume discovered to date
8) 1974-1991
9) includes Hudson Bay

ULTIMATE POTENTIAL ESTIMATES
FRONTIER AREAS
(Tcf)

	Canadian Petroleum Association[1]	Foothills Pipe Lines Ltd.	Gulf Oil Canada Limited
Beaufort-Mackenzie Basin	110-41-78	38.0	65
Arctic Islands	240-86-168	113.0	100-200
East Coast Offshore	200-60-110	142.0	130
Other Frontier Areas	23-6-14	6.5	7
Total	573-193-370	299.5	302-402

NOTE:
1) high-low-average estimates

April, 1975

SUPPLY– DELIVERABILITY

Jumping pond gas plant, Alberta

INTRODUCTION

Deliverability rather than reserves appears, under present circumstances, to be the limiting factor in determining whether increasing Canadian requirements and export commitments can be met. Deliverability, as defined in this report, is the rate at which established reserves can be produced in marketable form.

Recently, the reserves additions attributable to new discoveries in the conventional producing areas have declined, and much development drilling has been in reservoirs with low deliverability characteristics. This, together with rapid growth in domestic demand, caused the Board to become concerned that the deliverability from the conventional producing areas might not be capable, in the near future, of meeting both existing export commitments and growing domestic requirements. In these circumstances, an essentially volumetric protection formula, such as 25A4, could not ensure that growing Canadian requirements could be met.

It was primarily in this near term context that the present Hearing was undertaken by the Board; its purpose being to solicit evidence from interested parties in establishing the current deliverability from producing established reserves and the feasibility, economic and physical, of maximizing the deliverability from these reserves, to evaluate the economics of attachment and the deliverability potential of non-producing established reserves and to make some reasonable prediction as to the deliverability from projected future additions.

Deliverability depends on numerous physical, contractual, economic and regulatory factors.

The physical factors include reservoir rock characteristics, well completion techniques, the amount of associated liquid and impurity production, the number of producing wells, the capacity of the gathering system, the amount of compression available, the size of the processing plant and the availability of pipelines to move the gas to market.

The rate of production of a gas reservoir is agreed upon in a contract between the seller (the producer), and the purchaser (usually a distributor or transmission company). Historically, the contract rates of production have been negotiated to effect a compromise among the objectives of both parties, the producer desiring to realize a rapid return on his investment and the purchaser desiring to ensure a long-term supply of gas to allow amortization of his investment over an extended period of time, thus minimizing transportation costs. These negotiations have resulted in rates-of-take based on negotiated reserve estimates varying from 1:10,000 to 1:5,750 Mcf/d per MMcf

of initial reserves with many recent contracts being 1:7,300. Recently, some contracts have been primarily based on available deliverability where the purchaser of the gas buys whatever the producer can deliver. Examples of these are contracts for purchase of south-east Alberta shallow gas, and gas contracted to Pan-Alberta Gas Ltd. (Pan-Alberta).

Once the contract rate-of-take from a reservoir has been established, producing wells are drilled, a field gathering system is installed and a processing plant is constructed; unless they are subsequently expanded, these then become physical constraints on the deliverability of that reservoir. To minimize processing costs it is necessary to minimize excess processing capacity, and ensure a reasonable time period (at least three to five years) of throughput at plant capacity. This tends to discourage expansion unless major new reserves are developed in the area to feed the plant.

Economic factors which affect deliverability include prices, taxes, royalties, capital costs and operating costs. In general, producers are under no obligation to maintain the contract rate of production by drilling additional wells or installing additional compression, if they feel there is no economic incentive to do so. This economic incentive usually stems from the producer's desire to maximize present value profit through project acceleration. Investments for increased deliverability will only be made if the resulting rate-of-return is attractive compared with alternative investments.

One of the most important consideration in assessing the economic incentive to develop existing reserves and explore for additional reserves is the producer netback — that is, the wellhead price minus all taxes and royalties.

The actions of regulatory agencies can also have a bearing on gas deliverability. Provincial agencies regulate the quantity of gas which may be removed from a province on a daily, annual and cumulative basis. To prevent reservoir damage, they may also regulate the maximum producing rate of individual wells. In other cases they may defer production of gas from a reservoir to maximize the recovery of other hydrocarbons. The Board regulates the quantity of gas which may be exported from Canada on a daily, annual and cumulative basis.

Within the terms of reference of this Hearing, the most meaningful consideration of deliverability is the point at which it first exists in marketable form, which is at the field processing plant gate. This means that deliverability must reflect the constraints of all production facilities including processing plant capacity.

The determination and prediction of deliverability requires many assumptions to simplify the complex decision-making process of a multitude of producing companies, regulatory agencies and gas purchasers which make it materialize. As a result, deliverability forecasts are not conclusive — they require periodic review to incorporate actual performance to the extent possible and to incorporate changing economic and regulatory conditions.

A thorough assessment of deliverability requires detailed pool-by-pool analysis. Such studies are conducted by Board staff on a continuing basis.

The Board's deliverability forecasts for the conventional producing areas were derived from three categories of reserves:

(a) Producing Established (Committed) are established reserves which were included in gas purchase contracts as of December 31st, 1973. Where 85 percent or more of the reserves in a field are contracted, the uncontracted reserves in that field are included. Some pools in this category are not producing. However, since they make up part of the reserves which have been set aside under terms of the contract to generate the production rate specified in the contract, they are deemed to be on production.

(b) Non-producing Established (Uncommitted) are established reserves which are not included in gas purchase contracts as of December 31st, 1973 and where less than 85 percent of the reserves in the field are contracted. Not all pools in this category are now being produced.

(c) Reserves Additions are reserves which may be developed due to appreciation of established reserves and new discoveries. By definition new discoveries are not currently being produced but it is possible that the established reserves which provide the basis for reserves appreciation are now producing.

Forecast reliability is greatest for producing established reserves and least for new additions.

In general the submittors' forecasts fell into one or more of these categories. Although the submittors' definitions of the categories are not necessarily identical to those used for this report, these categories are used for comparative purposes.

CONVENTIONAL PRODUCING AREAS

(i) *Views of Submittors*

Nine submittors provided forecasts as to the established producing areas of Canada. The studies varied in complexity from detailed pool-by-pool studies using economic criteria to establish the amount of development which might occur, such as those submitted by the CPA and CAGSL, to aggregate forecasts based more on judgmental considerations. Examples of these were the forecasts of Foothills and the Ministry of Energy for Ontario.

The submittors' forecasts of total deliverability from the conventional producing areas ranged from 2,827 to 3,275 Bcf/year for 1977, a difference of 15 percent only three years hence. For 1980 the forecasts ranged from 2,730 to 3,461 Bcf/year, a difference of 14 percent. In 1977 the forecast of deliverability from producing established reserves ranged from 2,515 to 2,881 Bcf/year, a difference of 14 percent. For 1980 these forecasts varied from 2,259 to 2,738, a difference of 19 percent.

Most submittors prepared their forecasts assuming that production from producing established reserves would be maintained at or near present levels until decline commenced. One exception was a study done by McDaniel Consultants, commissioned by Foothills, which considered the economic feasibility of drilling infill wells and adding compression to facilitate substantially increasing the rate of production from producing established reserves in Alberta. It did not take into account processing plant or transportation constraints and assumed that only a 15 percent discounted cash flow return before taxes was necessary as incentive for the required investment. Although several submittors agreed that this type of scheme would be feasible for some pools, they did not think it was practical to achieve it on the scale suggested by the McDaniel study.

The view expressed by Gulf and the CPA was that the field processing plant expansion necessary to accommodate the higher rates of production would not be practical since it might only be utilized for a year or two before declining deliverability would lead to underutilization of the plant. They suggested that higher contract rates of take would be more practical for reserves that are not yet producing. CAGSL suggested that more stringent standards for gas plant stack emissions might discourage additional plant expansion, since substantial capital investments are already being undertaken to upgrade existing plants to conform with emission standards. Imperial stated that it had made no studies with regard to increasing contract production rates, since, in its opinion, transmission companies are more interested in the maintenance of current contract rates.

Several submittors, in particular the B.C. Energy Commission and Prof. Helliwell suggested that no firm evidence had been given to disprove the feasibility of the McDaniel study and that some consideration should be given to the concept, at least for the production of new reserves. Their opinion was that maximum deliverability should be developed from the less costly Southern Basin reserves before switching to more costly production from Frontier reserves. They did not submit any economic data to establish when that might occur. They suggested it was a question for further study to decide the most desirable time to connect frontier reserves.

The CPA submitted results of an economic study of the effect of producer netback on deliverability of existing pools in the conventional producing areas assuming no change in current contractual rates-of-take. It was assumed that a 15 percent discounted cash flow return after taxes of 50 percent and royalties of 50 percent, was required as incentive for additional investment in wells or compression. The results indicated approximately a five percent increase in deliverability for 1980 and a seven percent increase in 1985 if the price reached and remained at parity value instead of remaining at the May 1st, 1974 level in constant dollars.

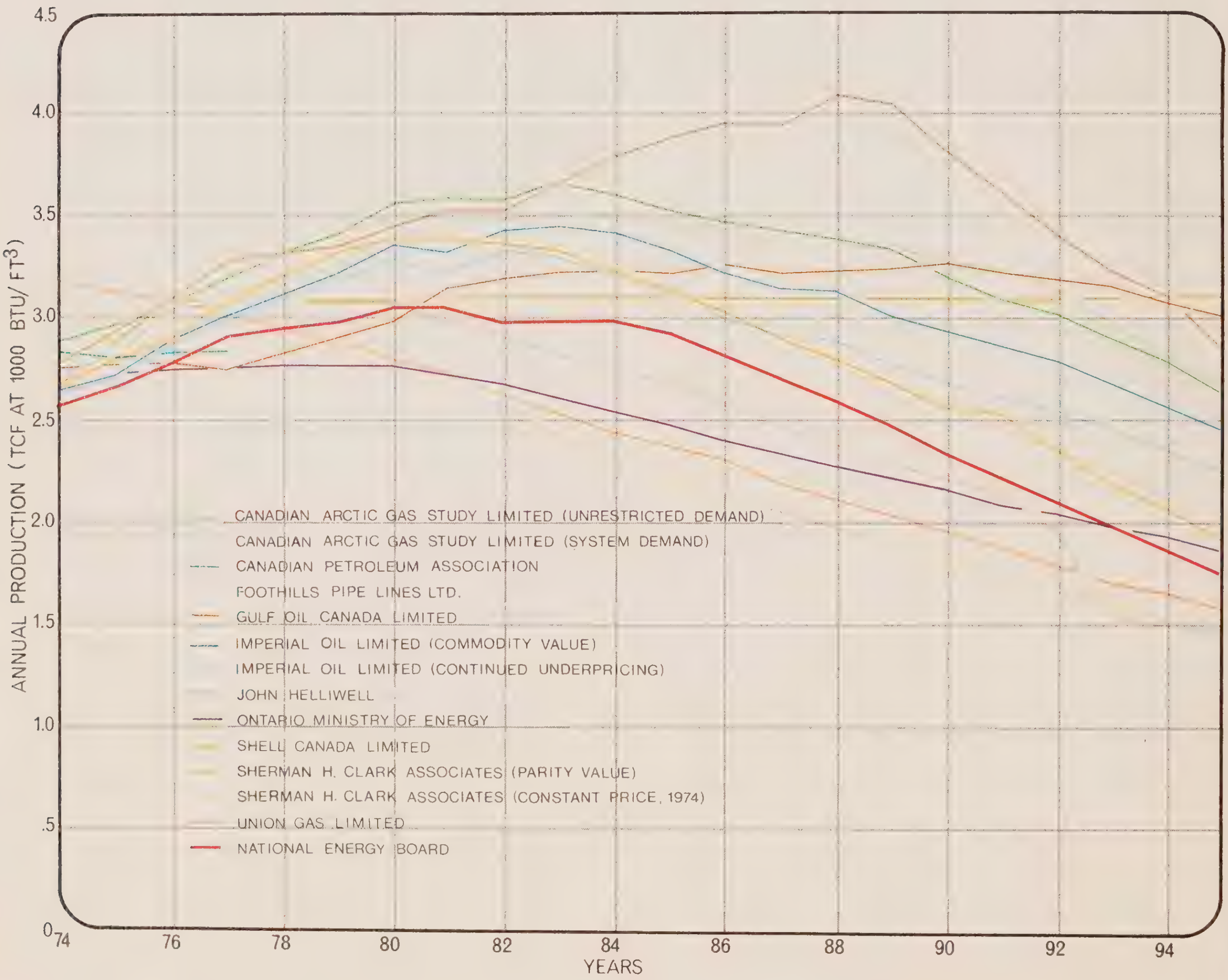
Although most submittors included production from non-producing established reserves in their forecasts, very little detailed evidence was submitted with respect to the scheduling of connection of specific fields and pools, or proof of their economic viability. Westcoast submitted a schedule for the connection of presently unconnected reserves in British Columbia. The B.C. Energy Commission submitted similar information.

TransCanada submitted the results of a study of the unconnected reserves in Alberta indicating their accessibility, contractual status and average transportation costs. On the basis of the study it found that there was approximately 5.8 Tcf of uncommitted gas in Alberta as of January 1975. However, of this uncommitted gas, 0.9 Tcf were deferred for conservation reasons, 1.5 Tcf were reserves in the Suffield Block which is being developed by the Province of Alberta, and another 1.2 Tcf were high cost — that is their average tie-in transportation cost alone was 72¢/Mcf. They concluded that only 2.2 Tcf were

readily available for purchase. The calculated average tie-in transportation cost of 1.7 Tcf of the 2.2 Tcf was 8.4¢/Mcf. The remaining 0.5 Tcf was the result of 50 exploratory discoveries during the period April to December 1974 and transportation costs were not calculated for these. Alberta and Southern Gas Co. Ltd. (Alberta and Southern) indicated that about 3.2 Tcf of uncommitted gas was available for purchase in Alberta, excluding the Suffield Block. Neither TransCanada or Alberta and Southern could provide a schedule of connection of this uncommitted gas.

Most submittors developed their forecasts of deliverability from reserves additions by assuming a rate-of-take from a forecast of the additions with allowance for the time required to develop and connect them. An exception was Prof. Helliwell who assumed the new additions would be available at whatever rate-of-take was required to meet demand.

Figure 16
CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS)
(Table 19)

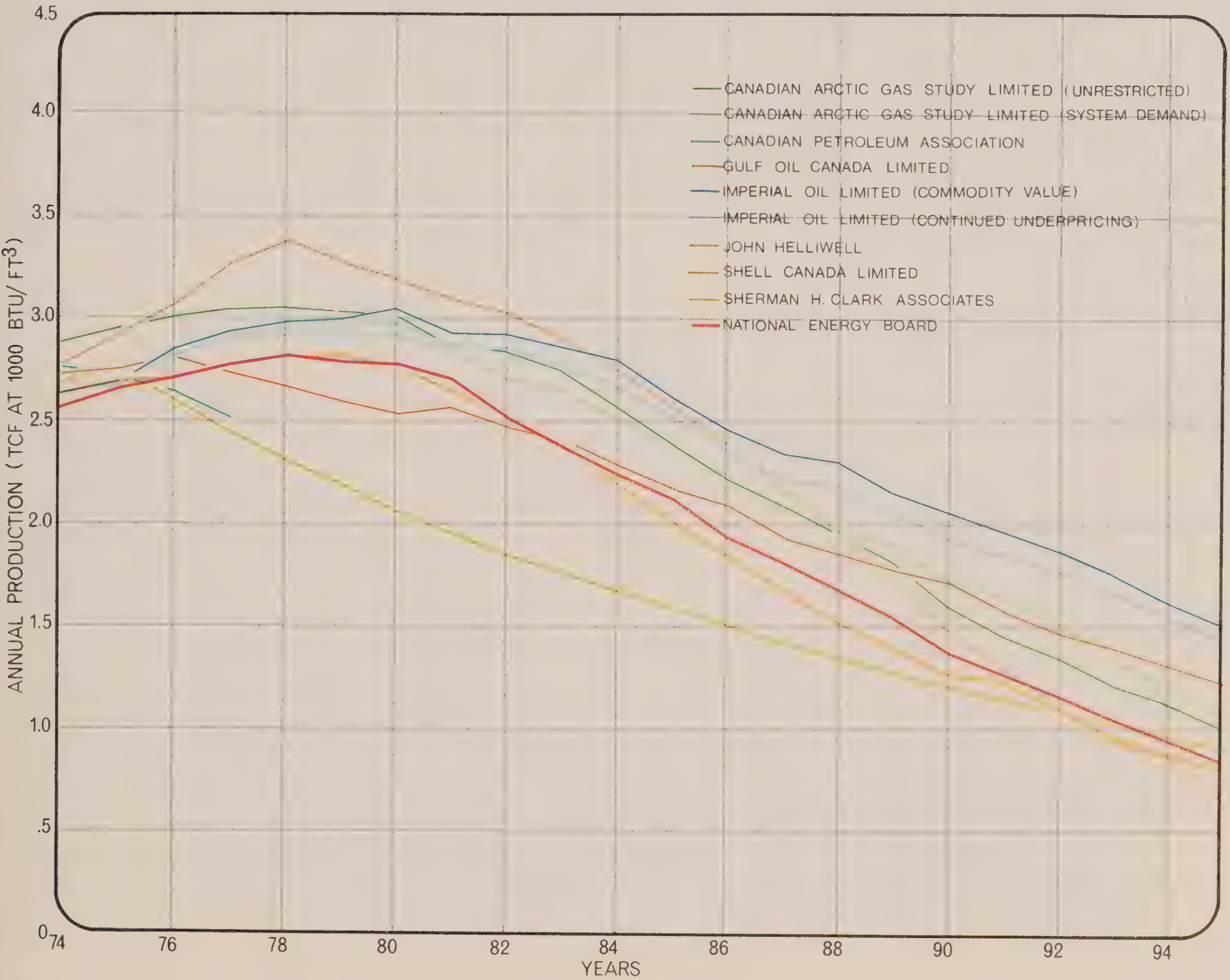


For comparative purposes, these deliverability forecasts were segregated, to the extent possible, into the reserves categories discussed in the introductory section. These classifications are approximate only, since they may not cover exactly the same reserves base. All forecasts were adjusted to 1000 Btu/cf where necessary and are illustrated in Figures 16, 17 and 18 (Tables 19, 20, 21) which includes the Board's forecast and show, respectively, the estimated total deliverability from the conventional producing areas from total established reserves plus reserves additions, total established reserves and producing established reserves.

Figure 17

CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (CONVENTIONAL PRODUCING AREAS WITH NO RESERVES ADDITIONS) FROM ESTABLISHED RESERVES ONLY

(Table 20)



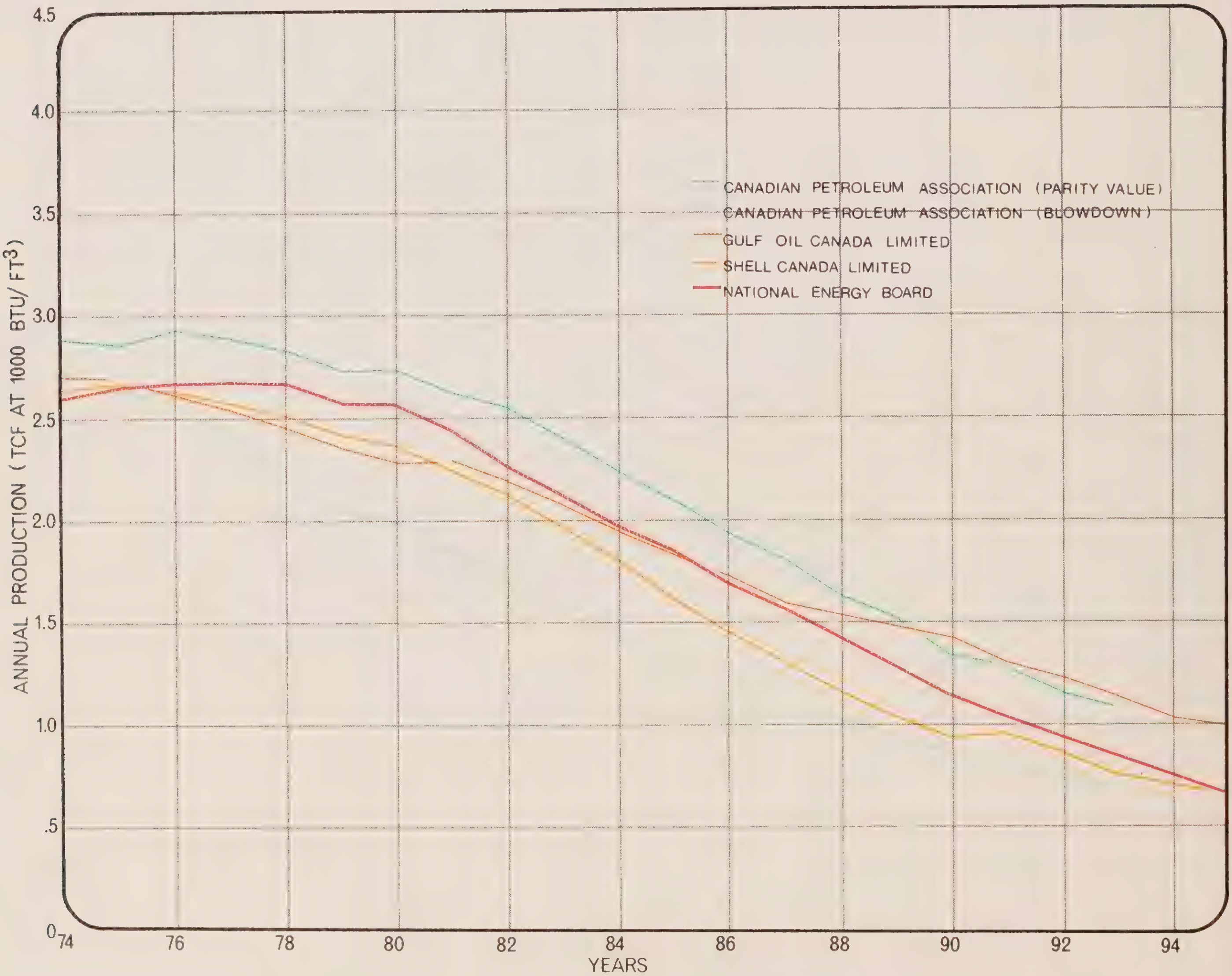
(ii) *Views of the Board*

The results of the Board's own detailed deliverability studies are shown separately in Figure 19 and Table 22. The deliverability from producing established reserves has been identified by major purchaser for reserves committed to them as of December 31st, 1973. The forecast production from non-producing established reserves is illustrated in total and has not been allocated to major purchasers. Likewise the possible production from reserves additions has also been shown in total.

The forecast of natural gas deliverability from currently producing reserves in the established areas of Canada was derived from independent, individual pool deliverability forecasts performed by Board staff. The detailed deliverability studies were based on Board estimates of established reserves; basic reservoir data including back pressure test results; processing plant capacities; contract quantities; and regulatory factors.

The assumption was made that producers would have sufficient incentive to maintain current production rates

Figure 18
CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (CONVENTIONAL PRODUCING AREAS WITH NO RESERVES ADDITIONS) FROM PRODUCING RESERVES ONLY
(Table 21)

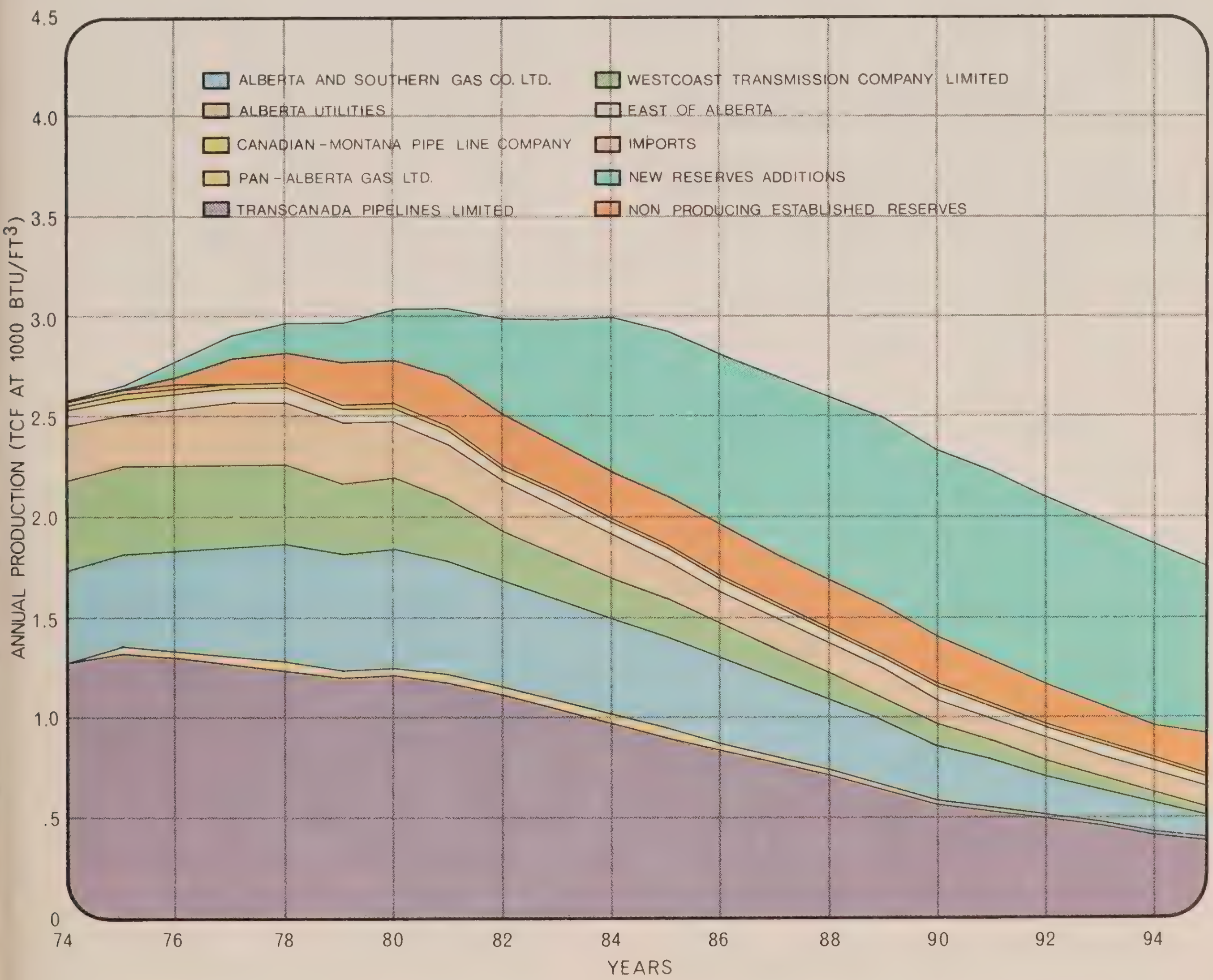


or contract quantities by installing additional compression as required until a minimum wellhead pressure was reached. It was assumed that additional wells would be drilled in those reservoirs where deliverability would otherwise decline prematurely.

It was also assumed that no major processing plant expansions would occur unless new reserves were developed.

The assumption was made that Alberta and Southern would continue to increase the rate of production from its committed reserves to the extent possible under terms of its gas purchase contracts, in an attempt to meet its Alberta requirements and to make gas available to markets east of Alberta. Reserves committed to TransCanada, Pan-Alberta, the Alberta utilities and Westcoast were also assumed to be produced at their maximum capability.

Figure 19
CANADIAN NATURAL GAS DELIVERABILITY (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) N.E.B. FORECAST
(Table 22)



The Board's forecast does not explicitly account for the economics of additional development in terms of additional compression or infill drilling. However,it is recognized that the production of any non-renewable resource, such as natural gas, is a rising real cost industry, in terms of both exploration and development, by virtue of the diminishing size of the undiscovered resource base and the depletion of established reserves. The costs of materials and labour are also increasing rapidly. The Board believes that continuing price increases will be necessary, if production of the order indicated in the Board's supply forecast is to be realized, and that these increases must be reflected in the producer netback. These price increases should be responsible to both the effect of price on consumer demand and the producer netback required to maintain a high level of activity in exploration and development.

Future gas production from non-producing established reserves was forecast on the basis of evidence submitted at the Hearing and the Board's own assessment of unconnected uncommitted reserves. The Board's view is that, at the end of 1973, there were some 2.8 Tcf of uncommitted non-producing established reserves available in Alberta, another 1.2 Tcf in the Suffield Block, and a further 1.0 Tcf of unconnected uncommitted reserves available in British Columbia, which could be tied in and commence production within the next five years.

The Board's forecast of production from reserves additions corresponding to the marketable reserves addition forecast in Table 14 was derived by assuming that production from each year's reserve growth would be phased in over the following five years to an eventual rate-of-take of 1:7,300. The possibility that reserves additions might include either beyond economic reach reserves or deferred reserves was taken into account by use of a diversity factor.

These reserves additions result from:

1) revisions to established reserves estimates;
2) extensions of existing pools; and
3) new discoveries

For the past several years the additions resulting from revisions and extensions have accounted for the greatest proportion of reserves additions in the conventional producing areas. Deliverability from additions due to revisions and extensions is linked to the contractual dedication and disposition of the established reserves with which they are associated. Only new discoveries are readily available for purchase by any buyer. Therefore, the Board adopted a conservative approach in forecasting the deliverability of this category of reserves. Although the Board agrees with some submittors that certain pools in this category will be depleted at rates-of-take higher than 1:7,300, it does not believe this will be achieved in the aggregate.

Consideration was also given to the possible effects of Alberta's protection of its requirements. In the Alberta Board's recent decisions on Alberta and Southern and Canadian-Montana Pipe Line Company applications to add additional fields to their removal permits, it reported a contractable surplus of 6.6 Tcf and a future surplus of 1.0 Tcf as of December 31st, 1974. However the Alberta Board expressed concern that its contractable surplus calculation did not realistically reflect the actual reserves available for purchase. It also noted that the future surplus had declined from 2.3 Tcf at May 31st, 1973 due to increasing future Alberta requirements. It further concluded it would be in the public interest to exercise caution in granting new permits or amending existing permits pending better definition of the Alberta surplus. The Alberta Board subsequently approved the application by Canadian Montana and denied the application by Alberta and Southern.

From a reivew of TransCanada's existing supply, it is apparent it will have to add substantially to the list of fields and pools from which it may remove gas from the province under Permits TCPL 70-10 and CNG 69-1 in order to sustain even existing withdrawals from Alberta. The current level of withdrawals from the province is now slightly in excess of the maximum annual volumes authorized under TCPL 70-10 with the excess being removed under "make-up" provisions. If and when the Government of Alberta approves Permit TCPL 73-11, the maximum annual withdrawals from the province will be increased by 163 Bcf and additional fields will become available to supply the gas to be removed. However, further additional fields and pools would have to be named in this permit in order to sustain existing levels of withdrawals or attain the maximum annual withdrawals under TCPL-73-11. In preparing its forecast, the Board has assumed that the Alberta Board will name additional fields in TransCanada's permit to allow it to attain the maximum annual withdrawals authorized by Permit TCPL 73-11 but will not permit further increases in the maximum annual

withdrawals from the province pending clarification of the Alberta surplus by the Alberta Board.

Since Pan Alberta no longer has under contract much of the gas in fields named in its removal permit, the Board anticipates that the Alberta Board may revise downward Pan Alberta's present Alberta removal permit to reflect the decrease in contracted reserves. Therefore, for purposes of arriving at the Board's forecast, it was assumed that only withdrawals based on production forecast from Pan Alberta's presently contracted reserves will be permitted. The Board recognizes that, in fact, Pan Alberta may purchase additional gas and remove it from the province but these volumes would probably restrict the new fields which can be added under TransCanada's removal permits.

In preparing the Board's forecast of deliverability from the conventional producing areas, two cases were considered and are illustrated in Figure 20. In the high development case it was assumed that additional development drilling and compression installation would occur in presently producing reserves and that presently unconnected reserves and new reserves additions would be produced at a rate-of-take of 1:7,300. In the low development case it was assumed that only additional compression installation would occur in producing established reserves, and that deliverability from reserves additions and non-producing established reserves would be significantly less than that available in the high development case.

The Board's forecast, illustrated on Figures 19 and 20 reflect the Board's concern that:

1) The deliverability from non-producing established reserves and reserves additions may not be available at historical rates-of-take due to poor deliverability characteristics or high processing requirements.

2) The Alberta Board or the Government of Alberta may not permit increases in the annual volumes which may be removed from the province.

3) The time taken to resolve federal-provincial differences over resource taxation and pricing may have a negative effect on the industry's efforts to sustain deliverability and attach new reserves.

Because of these considerations, the Board's forecast essentially follows the Low Development Case during the early portion of the forecast period and the High Development Case during the latter portion of the forecast period.

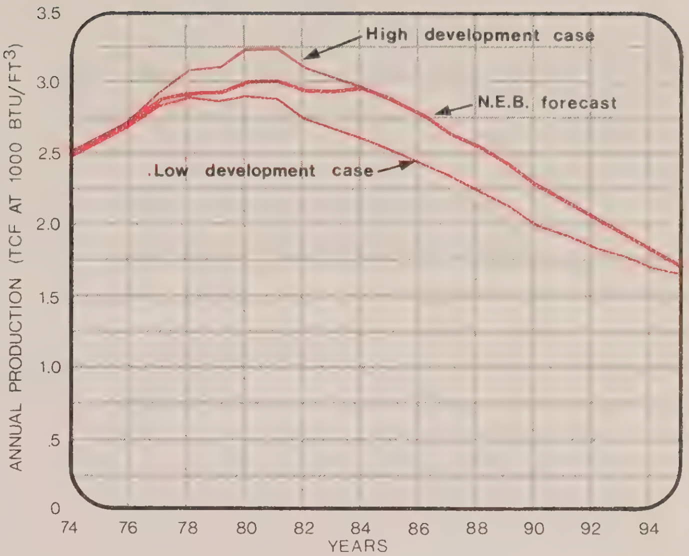


Figure 20

CANADIAN NATURAL GAS DELIVERABILITY (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) COMPARISON OF N.E.B. LOW, HIGH AND FORECAST CASES

It should be emphaiszed that the Board believes it will require willingness to invest new funds on the part of the producing industry as well as co-operation between governments, the producing industry and the transmission and distribution companies to attain the levels of deliverability which comprise the Board's forecast.

Figure 21 and Table 23 show the Board's forecast of total deliverability from the conventional producing areas in Figure 19 compared with a forecast from producing established reserves with additional compression only. The graph and table illustrate that, without substantial additional drilling, and connection of presently unconnected reserves including new additions, the Board's forecast for 1980 shown in Figure 19 might be reduced by some 20 percent.

The Board does not believe that acceleration of production from the conventional producing areas to the degree implicit in the McDaniel study is likely to be achieved, because of the numerous practical limitations cited during the Hearing. Even if it were possible, the Board is not convinced that it would be desirable, until more definitive assurance of the availability of Frontier supplies at a rate capable of off-setting the eventual rapid decline in deliverability in the conventional producing areas can be provided.

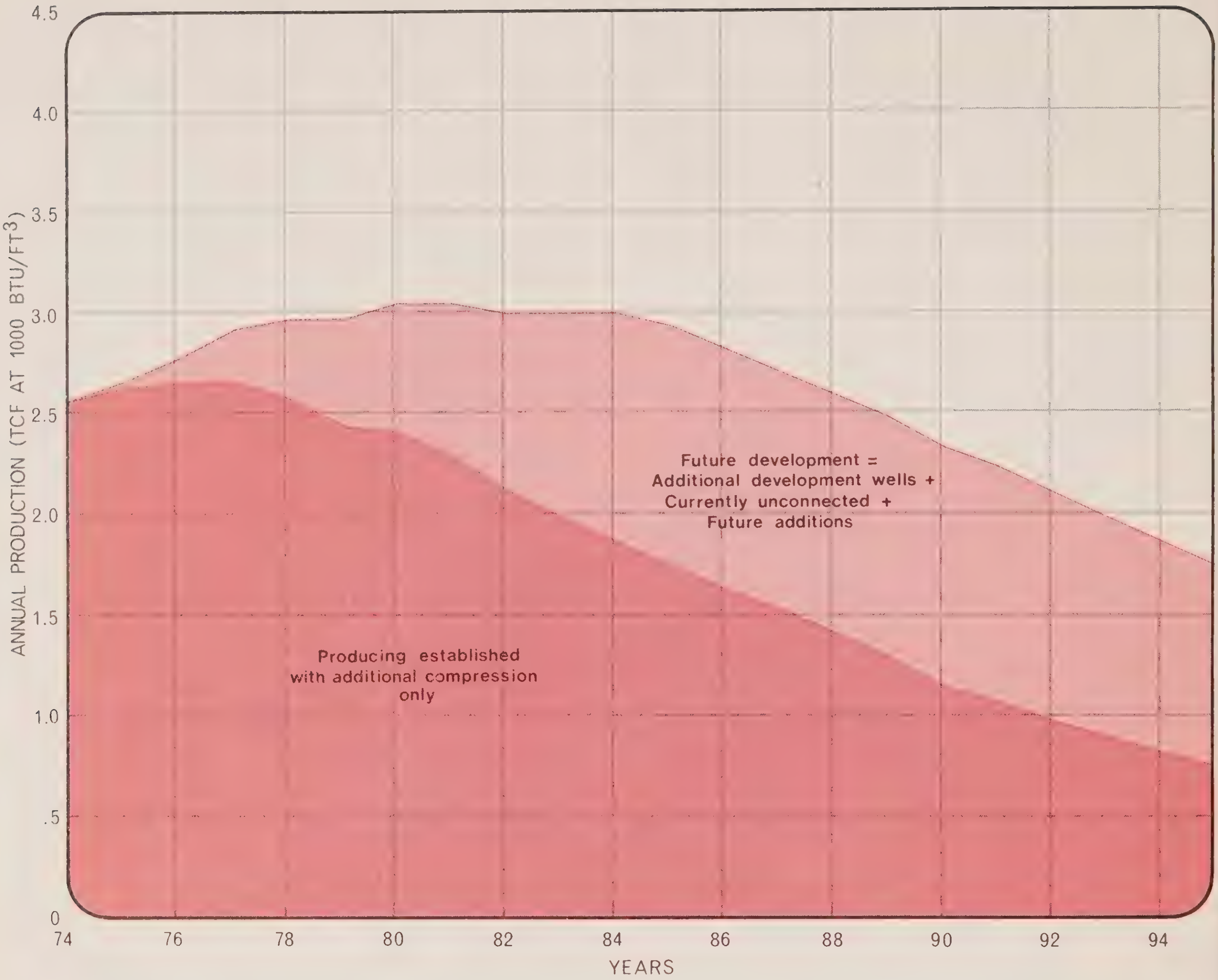


Figure 21
CANADIAN NATURAL GAS DELIVERABILITY (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) SIGNIFICANCE OF FUTURE DEVELOPMENT IN NEB FORECAST
(Table 23)

The Board attaches considerable importance to assuring Canada of a long term supply of natural gas. This can only be achieved by ensuring that exploration for new reserves is conducted vigorously, in both the conventional producing and Frontier areas. With the uncertainty and risk involved in the discovery of new reserves in either area and the flexibility of natural gas transmission systems, it is prudent to develop deliverability from the conventional producing areas only to a level capable of being supported for a reasonably long time.

FRONTIER AREAS

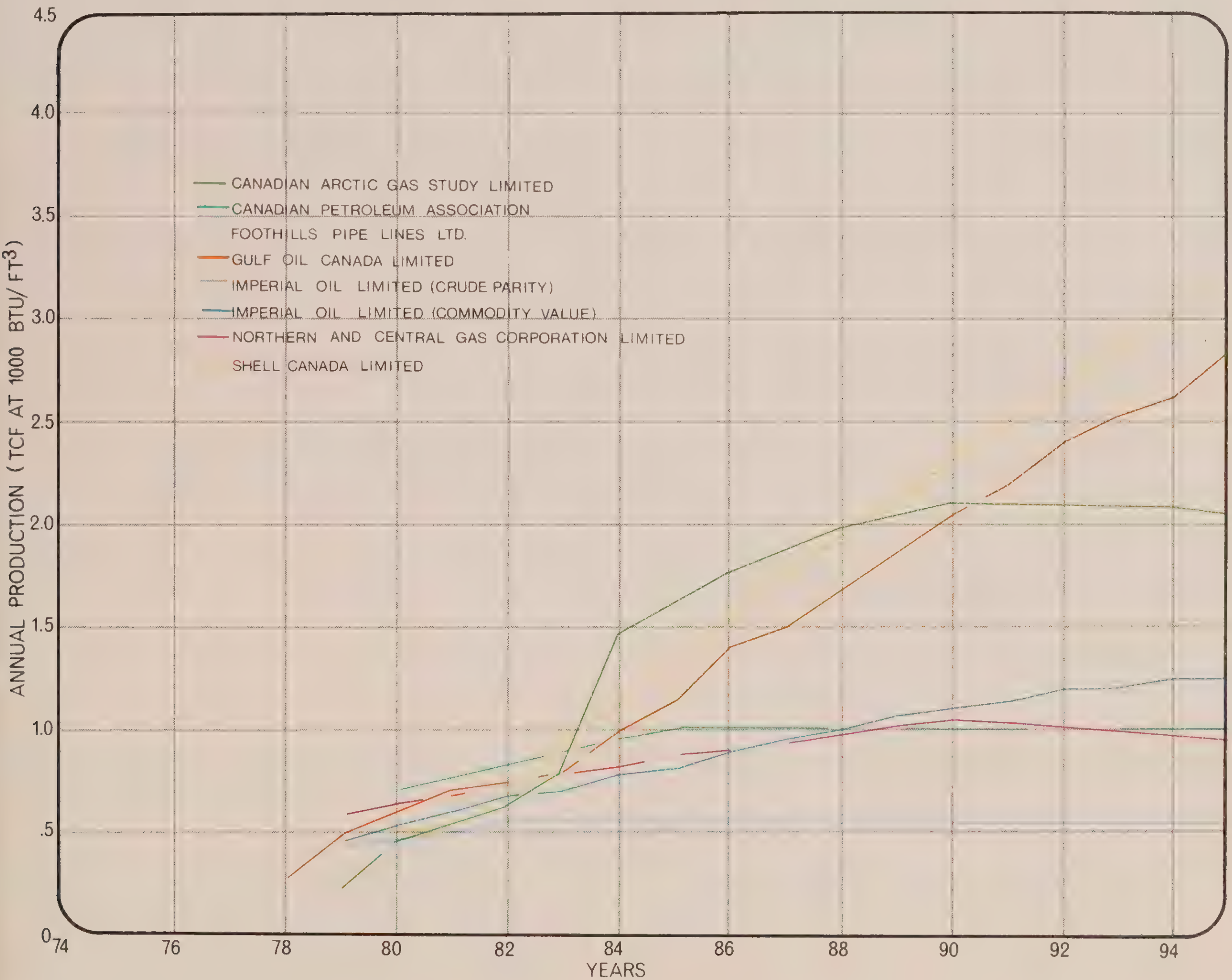
(i) *Views of Submittors*

Forecasts of deliverability from the Frontier areas of Canada were provided by six submittors. In general these forecasts were based on either an assumed rate-of-take from a schedule of reserve additions or the capacity of proposed transmission lines. The forecasts submitted are illustrated in Figures 22, 23 and 24 (Tables 24, 25, 26) for the Mackenzie Delta-Beaufort Area, Arctic Islands and East Coast Offshore, respectively.

(ii) *Views of the Board*

In view of the wide range of estimates made by the submittors and the early stage of exploration of these areas, the Board does not believe it would be prudent to attempt to quantify either the anticipated reserve addition rate or the deliverability therefrom. However, the Board does consider that significant levels of deliverability may be developed in the future from these areas.

Figure 22
CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (FRONTIER AREAS) BEAUFORT SEA AND MACKENZIE DELTA
(Table 24)



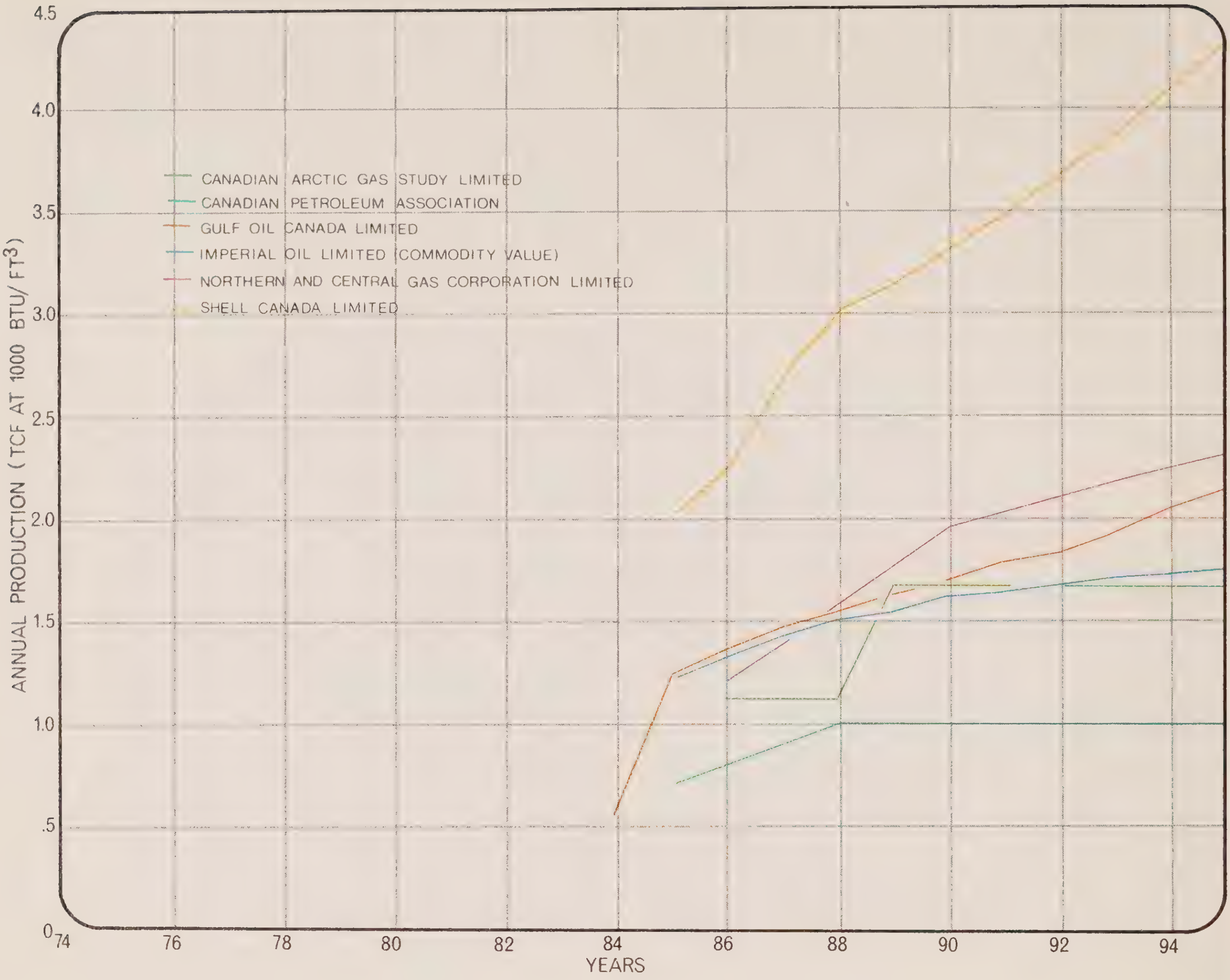


Figure 23
CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (FRONTIER AREAS) ARCTIC ISLANDS
(Table 25)

OTHER POSSIBLE SUPPLY SOURCES

(i) *Views of Submittors*

Very little detailed evidence was provided during the Hearing with respect to synthetic natural gas. At least one submittor felt that, based on experience with development of new technology in the form of tar sands plants, it was not wise to rely on gas supplies from coal gasification.

No evidence was received on the possible use of LNG imports to supplement indigenous gas supplies.

(ii) *Views of the Board*

Concerning coal gasification, the Board considers the conversion of Canadian coal to high Btu (950 Btu/cf) gas has not been proven on a large scale. Areas of concern with respect to technical feasibility are the suitability of Canadian coal for the proven gasification processes that

convert coal to medium Btu (250-550 Btu/cf) gas and the methanation process to convert medium Btu gas to high Btu gas.

Until the first coal gasification plant is in operation and its economics and environmental acceptability are proven, the Board considers it premature to incorporate this source of supply in its gas supply forecasts.

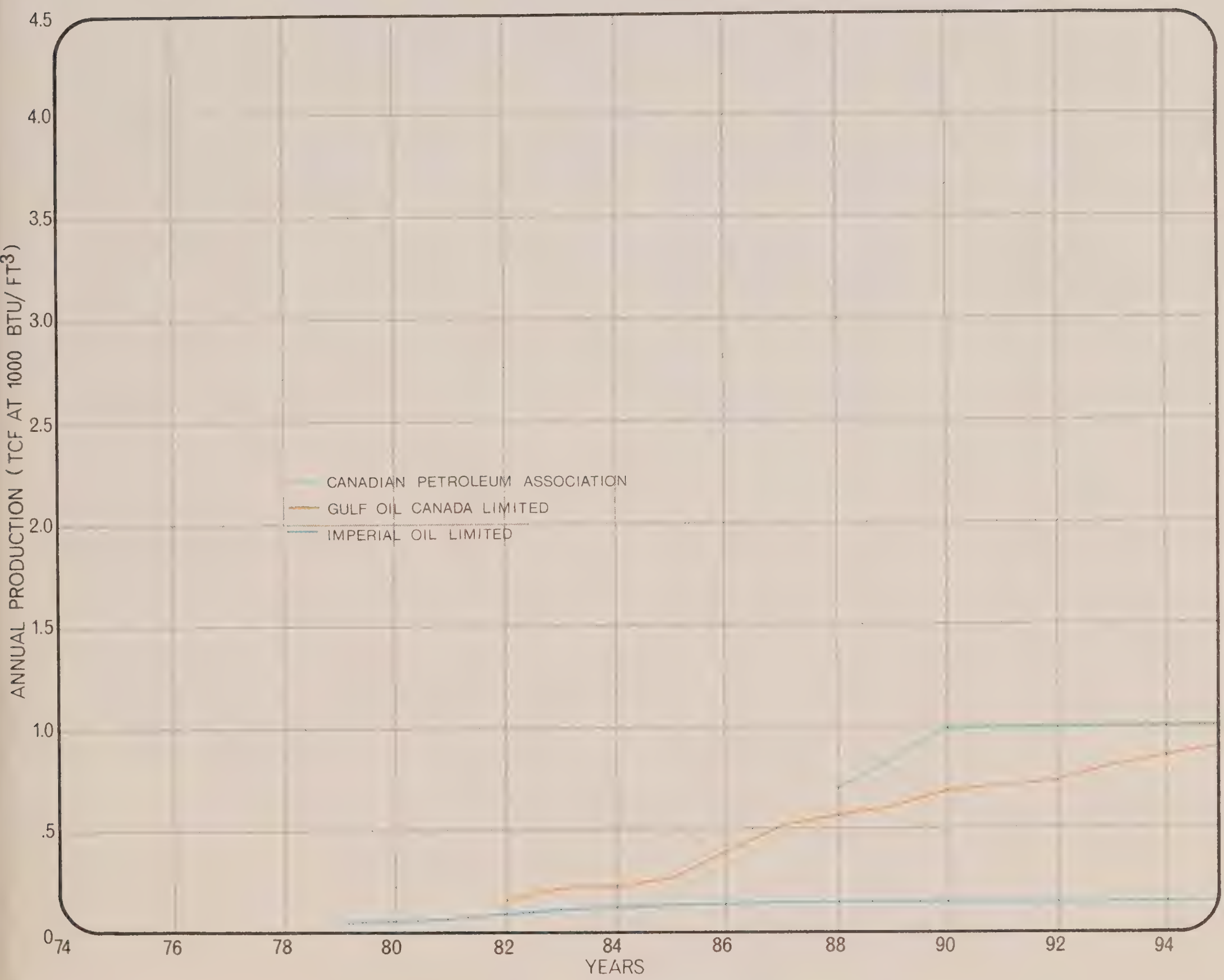


Figure 24

CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (FRONTIER AREAS) EAST COAST

(Table 26)

CANADIAN NATURAL GAS DELIVERABILITY FORECASTS (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS)

(Bcf/yr @ 1000 BTU/FT^3)

Year	N.E.B.	Shell Canada Ltd.	Imperial Oil Limited (High)	Imperial Oil Limited (Low)	Gulf Oil Canada Limited	John Helliwell	Canadian Petroleum Association	Canadian Arctic Gas Study Limited (High)	Canadian Arctic Gas Study Limited (Low)	Foothills Pipe Lines Limited	Minister of Energy Ontario	Sherman H. Clark (High)	Sherman H. Clark (Low)	Union Gas Limited
1974	2566	2649	2640	2640	2734	2759	2821	2892	2665	2710	2660	2667	2667	3159
75	2651	2815	2720	2710	2752	2933	2794	2972	2777	2825	2710	2929	2929	3117
76	2788	2907	2900	2880	2759	3079	2802	3073	2904	3054	2720	3086	3054	3075
77	2909	3077	3010	2980	2738	3275	2827	3200	3053	3060	2740	3086	3012	3002
78	2967	3212	3120	3080	2817	3312	–	3317	3163	3092	2750	3086	2929	2929
79	2970	3332	3230	3130	2880	3356	–	3422	3278	3096	2750	3086	2824	2877
80	3043	3394	3370	3290	2968	3461	–	3553	3419	3094	2750	3086	2730	2782
81	3041	3393	3340	3230	3128	3573	–	3597	3468	2988	2705	3096	2625	2720
82	2986	3375	3440	3310	3186	3574	–	3570	3482	2906	2653	3107	2531	2615
83	2985	3334	3450	3300	3230	3659	–	3660	3521	2827	2595	3107	2437	2531
84	2992	3243	3420	3230	3219	3786	–	3607	3503	2770	2525	3107	2333	2437
85	2927	3125	3330	3140	3215	3883	–	3520	3465	2695	2455	3107	2238	2364
86	2810	3027	3230	3000	3252	3947	–	3472	3445	2582	2385	3107	2144	2301
87	2697	2913	3140	2910	3223	3941	–	3427	3349	2465	2325	3107	2061	2197
88	2594	2803	3130	2890	3226	4095	–	3381	3367	2403	2265	3107	1977	2113
89	2480	2688	3010	2780	3238	4050	–	3329	3362	2307	2205	3107	1904	2040
90	2325	2554	2940	2680	3260	3801	–	3194	3264	2239	2150	3107	1820	1966
91	2226	2532	2870	2620	3219	3608	–	3094	3236	2170	2085	3107	1747	1883
92	2095	2364	2790	2560	3190	3416	–	3007	3136	1969	2030	3107	1674	1778
93	1986	2195	2690	2470	3136	3243	–	2901	2979	1537	1975	3117	1600	1705
94	1855	2056	2570	2360	3073	3118	–	2778	2807	1510	1920	3117	1527	1663
95	1746	1915	2470	2260	3007	2859	–	2648	2662	1472	1860	3117	1464	1579

April, 197[illegible]

CANADIAN NATURAL GAS DELIVERABILITY FORECASTS
(CONVENTIONAL PRODUCING AREAS WITH NO RESERVES ADDITIONS) FROM ESTABLISHED RESERVES ONLY

(Bcf/yr @ $1000\ BTU/FT^3$)

Year	N.E.B.	Shell Canada Limited	Imperial Oil Limited (high)	Imperial Oil Limited (low)	Gulf Oil Canada Limited	John Helliwell	Canadian Petroleum Association	Canadian Arctic Gas Study Limited (high)	Canadian Arctic Gas Study Limited (low)	Sherman H. Clark
1974	2566	2649	2640	2640	2734	2782	2771	2892	2665	2667
75	2666	2714	2700	2690	2752	2939	2694	2953	2757	2751
76	2710	2733	2860	2840	2759	3096	2652	3007	2840	2604
77	2794	2792	2940	2910	2738	3295	2527	3053	2906	2458
78	2823	2825	2990	2950	2675	3389	—	3059	2917	2333
79	2777	2837	3000	2960	2595	3284	—	3042	2912	2207
80	2786	2790	3050	2990	2548	3201	—	3043	2927	2092
81	2700	2672	2930	2860	2566	3107	—	2936	2849	1987
82	2504	2548	2930	2860	2478	3033	—	2794	2734	1883
83	2373	2402	2860	2790	2405	2808	—	2757	2651	1789
84	2232	2219	2760	2670	2285	2761	—	2586	2519	1695
85	2105	2029	2620	2540	2164	2573	—	2389	2375	1600
86	1959	1859	2480	2370	2091	2385	—	2239	2257	1517
87	1808	1690	2350	2240	1938	2176	—	2095	2065	1433
88	1681	1537	2310	2200	1854	1987	—	1956	1994	1360
89	1550	1402	2160	2060	1778	1747	—	1818	1906	1287
90	1379	1273	2070	1940	1712	1496	—	1606	1734	1224
91	1278	1250	1980	1860	1584	1308	—	1458	1659	1161
92	1153	1110	1880	1790	1482	1119	—	1346	1535	1098
93	1056	985	1760	1680	1391	952	—	1234	1373	1036
94	945	900	1620	1560	1303	868	—	1122	1211	983
95	857	814	1510	1450	1226	669	—	1016	1089	931

April, 1975

CANADIAN NATURAL GAS DELIVERABILITY FORECASTS
(CONVENTIONAL PRODUCING AREAS WITH NO RESERVES ADDITIONS)
FROM PRODUCING RESERVES ONLY

(Bcf/yr @ 1000 BTU/FT^3)

Year	N.E.B.	Shell Canada Limited	Gulf Oil Canada Limited	Canadian Petroleum Association (high)	Canadian Petroleum Association (low)
1974	2566	2649	2683	2866	2721
75	2626	2662	2654	2855	2619
76	2652	2629	2599	2917	2552
77	2659	2583	2515	2881	2402
78	2654	2512	2431	2811	2196
79	2549	2419	2329	2720	2016
80	2553	2372	2259	2738	1995
81	2441	2254	2267	2601	1861
82	2245	2130	2164	2558	1719
83	2114	1985	2057	2395	1555
84	1973	1805	1931	2240	1418
85	1844	1620	1803	2080	1293
86	1689	1460	1719	1946	1155
87	1547	1302	1584	1801	1074
88	1420	1165	1518	1636	1010
89	1289	1050	1456	1518	948
90	1132	948	1405	1321	849
91	1044	959	1292	1266	784
92	936	861	1205	1150	740
93	857	777	1124	1090	702
94	760	724	1055	–	
95	685	666	989	–	

April, 1975

CANADIAN NATURAL GAS DELIVERABILITY

CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS

N.E.B. FORECAST

(Bcf/yr at 1000 Btu per cubic foot)

Year	Established Reserves							New Reserves Additions	Total
	Producing					Non Producing	Total	Total	
	TransCanada PipeLines Limited & Pan-Alberta Gas Ltd.	Alberta and Southern Gas Company Limited	Westcoast Transmission Company Limited	Other	Total	Total			
1974	1270	465	403	428	2566	–	2566	–	2566
75	1355	465	390	416	2626	–	2626	25	2651
76	1332	505	377	438	2652	58	2710	78	2788
77	1306	545	361	447	2659	135	2794	115	2909
78	1275	587	356	436	2654	169	2823	144	2967
79	1237	578	305	429	2549	228	2777	193	2970
80	1246	599	296	412	2553	233	2786	257	3043
81	1212	568	277	384	2441	259	2700	341	3041
82	1148	533	248	316	2245	259	2504	482	2986
83	1080	504	229	301	2114	259	2373	612	2985
84	1001	481	210	281	1973	259	2232	760	2992
85	934	466	187	257	1844	261	2105	822	2927
	(1)	(2)	(3)	(4)	(5) (1+2+3+4)	(6)	(7) (5+6)	(8)	(9) (7+8)

April, 1975

CANADIAN NATURAL GAS DELIVERABILITY
CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS
SIGNIFICANCE OF FUTURE DEVELOPMENT IN N.E.B. FORECAST
(BCF/YR at 1000 Btu per cubic foot)

Year	Established Reserves					New Reserves Additions	Total
	Producing			Non-Producing	Total	Total	
	With Additional Compression	Effect of Infill Drilling	Total	Total			
1974	2566	–	2566	–	2566	–	2566
75	2626	–	2626	–	2626	25	2651
76	2652	–	2652	58	2710	78	2788
77	2659	–	2659	135	2794	115	2909
78	2573	81	2654	169	2823	144	2967
79	2432	117	2549	228	2777	193	2970
80	2407	146	2553	233	2786	257	3043
81	2290	151	2441	259	2700	341	3041
82	2105	140	2245	259	2504	482	2986
83	1983	131	2114	259	2373	612	2985
84	1851	122	1973	259	2232	760	2992
85	1747	97	1844	261	2105	822	2927
	(1)	(2)	(3) (1+2)	(4)	(5) (3+4)	(6)	(7) (5+6)

April, 1975

CANADIAN NATURAL GAS DELIVERABILITY/PRODUCTION FORECASTS
FRONTIER AREAS (BEAUFORT SEA & MACKENZIE DELTA)

(Bcf/yr @ 1000 Btu/ft^3)

Year	Imperial Oil Limited (Crude Parity)	Imperial Oil Limited (Commodity)	Canadian Arctic Gas Study Limited	Shell Canada Ltd.	Foothills	Gulf Oil Canada Limited	Northern & Central	Canadian Petroleum Association
1974	–	–	–	–	–	–	-	-
1975	–	–	–	–	–	–	–	–
1976	–	–	–	–	–	–	–	–
1977	–	–	–	–	–	–	–	–
1978	–	–	–	–	–	256	–	–
1979	400	440	225	–	80	475	578	–
1980	440	510	457	499	496	584	630	700
1981	470	580	542	555	592	694	682	760
1982	510	660	641	622	704	730	734	820
1983	510	690	787	954	784	784	786	880
1984	510	770	1481	1128	864	986	838	940
1985	510	800	1623	1324	864	1132	873	1000
1986	510	880	1764	1540	864	1382	908	1000
1987	510	950	1880	1775	864	1497	943	1000
1988	510	990	1982	1950	864	1679	978	1000
1989	510	1060	2042	2137	864	1862	1013	1000
1990	510	1100	2103	2236	864	2044	1048	1000
1991	510	1130	2100	2509	864	2188	1025	1000
1992	510	1200	2093	2692	864	2409	1003	1000
1993	510	1200	2087	2879	864	2520	981	1000
1994	510	1240	2080	3044	864	2628	960	1000
1995	510	1240	2056	3205	864	2847	939	1000

April, 1975

CANADIAN NATURAL GAS DELIVERABILITY/PRODUCTION FORECASTS
FRONTIER AREAS (ARCTIC ISLANDS)
(Bcf/yr @ 1000 Btu/ft^3)

Year	Imperial Oil Limited (Commodity)	Canadian Arctic Gas Study Limited	Shell Canada Ltd.	Gulf Oil Canada Limited	Northern & Central	Canadian Petroleum Association
1974	–	–	–	–	–	
75	–	–	–	–	–	
76	–	–	–	–	–	–
77	–	–	–	–	–	–
78	–	–	–	–	–	–
79	–	–	–	–	–	–
80	–	–	–	–	–	–
81	–	–	–	–	–	
82	–	–	–	–	–	–
83		–	–	–	–	–
84	–	–	–	548	–	–
85	1200	–	2017	1241	–	700
86	1310	1107	2262	1351	1219	800
87	1420	1107	2720	1460	1398	900
88	1500	1107	3010	1525	1584	1000
89	1530	1665	3158	1624	1778	1000
90	1610	1665	3320	1697	1964	1000
91	1640	1665	3500	1770	2044	1000
92	1680	1665	3692	1825	2121	1000
93	1700	1665	3895	1916	2190	1000
94	1720	1665	4106	2044	2256	1000
95	1750	1665	4329	2117	2318	1000

April, 1975

TABLE 5

CANADIAN NATURAL GAS DELIVERABILITY/PRODUCTION FORECASTS FRONTIER AREAS (EAST COAST)

(Bcf/yr @ 1000 Btu/ft^3)

Year	Imperial Oil Limited (crude or commodity)	Gulf Oil Canada Limited	Canadian Petroleum Association
1974	–	–	–
75	–	–	–
76	–	–	–
77	–	–	–
78	–	–	–
79	40	–	–
80	60	–	–
81	70	–	–
82	90	164	–
83	110	219	–
84	120	219	–
85	130	256	–
86	140	383	–
87	150	511	–
88	150	566	700
89	150	600	850
90	150	675	1000
91	150	712	1000
92	150	730	1000
93	150	803	1000
94	150	854	1000
95	150	913	1000

April, 1975

SUPPLY/DEMAND BALANCE

Construction of pipeline loop, east of Burstall Saskatchewan

Housing development using natural gas

TOTAL CANADA

The relationship between the Board's forecast of supply from the conventional producing areas plus submittors' forecasts of supply from the Frontier areas and the Board's Scenario II forecast of potential demand for Canada and authorized exports is illustrated in Figure 25.

It is apparent from Figure 25 that the current inability of supply to meet all requirements for Canadian natural gas, (licensed exports plus growing domestic demand), is likely to continue at least until supplies from the Frontier areas become available. Without substantial supplies from Canada's Frontier areas, growing domestic requirements could not be satisfied beyond 1984 even if all exports were diverted to domestic markets as required. Without substantial further development of the conventional producing areas they could not be satisfied beyond 1979 even with exports diverted to domestic markets as required to meet domestic deficiencies.

If the forecasts of potential deliverability from the Frontier areas submitted by Gulf and Imperial materialize, it is possible that Canada may be able to satisfy both growing domestic requirements and currently licensed exports from 1981 to the end of the forecast period. However, this is by no means assured at the present time.

If there is a lack of adequate supplies of gas for the domestic markets in the late 1970's, then the potential demand shown in the Board's forecast would not be realized as the market would not be attached and developed to the same extent. If there were a return to adequate supplies in the 1980's, growth in the markets would resume immediately. Some of the lost markets would gradually be recaptured, such that by the mid – 1980's the demand curtailed in the 1970's would be almost completely reinstated. The end result is that the actual consumption in the latter part of the forecast period would closely approximate the potential demand forecast in this report.

The forecast of deliverability from the conventional producing areas was segregated into three requirement areas: British Columbia, Alberta, and East of Alberta in Figures 26, 27 and 29. The deliverability in excess of Alberta and Southern firm requirements is shown in Figure 28. This excess was assumed available to offset defeciencies of gas to meet requirements in Alberta and East of Alberta and is included in Figures 25, 27 and 29.

BRITISH COLUMBIA

Figure 26 illustrates the natural gas supply available to meet British Columbia domestic requirements plus exports by Westcoast under GL-4. The supply includes:

a) Producing established reserves in British Columbia, Alberta, the Northwest Territories and the Yukon supplying the Westcoast Mainline Transmission system.

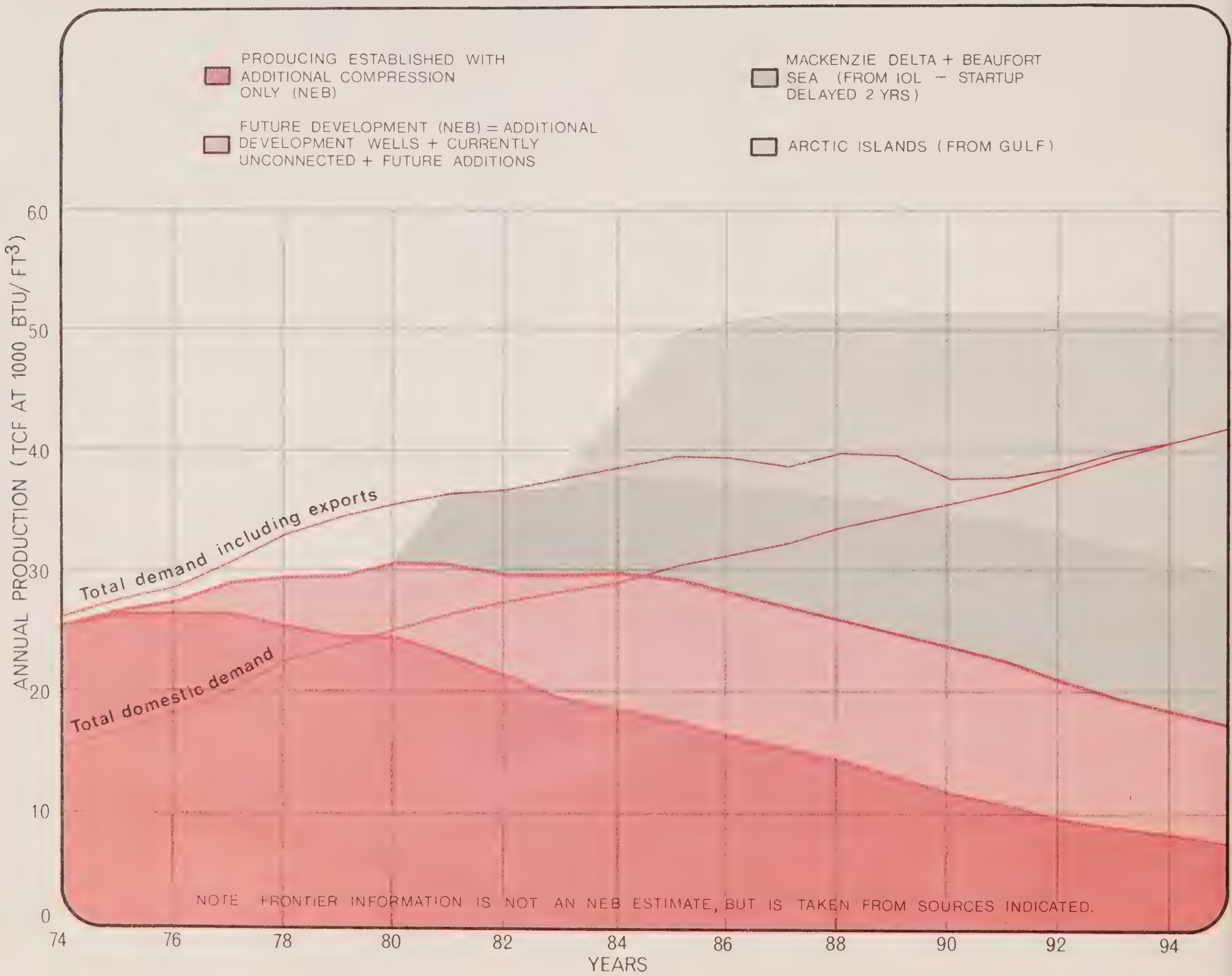
b) Non-producing established reserves in British Columbia.

c) Reserves additions forecast for British Columbia.

It should be noted that the recent short term sale of gas by Pan-Alberta to Westcoast was not included in the illustrated supply.

During 1974 the volume of gas which was exported under GL-41 was 40 Bcf less than the licenced maximum annual volume. As shown in Figure 26 the forecasted deficiency for 1975 is approximately 90 Bcf. The increased deficiency results from a continuing decline in deliverability, and an increase in domestic requirements of approximatly 40 Bcf. As noted previously, the domestic require-

Figure 25
CANADIAN NATURAL GAS SUPPLY AND DEMAND (NEB FORECASTS FOR THE CONVENTIONAL PRODUCING AREAS AND SUBMITTORS FORECASTS FOR THE FRONTIER AREAS)



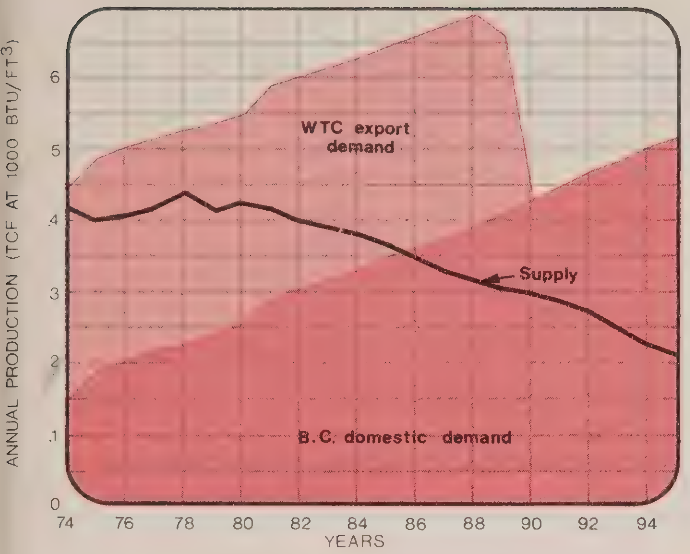


Figure 26
NATURAL GAS SUPPLY AVAILABLE TO MEET BRITISH COLUMBIA REQUIREMENTS (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) NEB FORECASTS

ments are potential requirements assuming no supply constraints. Therefore the forecast demand includes a requirements for the Burrard thermal plant which is 27 Bcf greater than the actual 1974 consumption. The abnormally low 1974 consumption resulted from Westcoast's supply constraint.

It may be possible to stabilize the supply deficiencies in British Columbia at approximately 100/Bcf year until 1978. However, the potential loss of deliverability from the Clark Lake field about that time, as a result of water production, will foreshadow a period of declining deliverability which will continue until the end of the forecast period. Even if exports were deverted as required to next domestic deficiencies, growing domestic requirements could not be met beyond 1985, from the sources referred to above.

ALBERTA

Figure 27 depicts the natural gas supply available to meet Alberta requirements plus exports by Alberta and Southern, Canadian-Montana and Westcoast under the Board's Licence No. GL-4. The supply includes;

a) Producing established reserves in Alberta supplying Alberta requirements and the Alberta and Southern and Canadian-Montana systems plus exports by Westcoast under GL-4.

b) Non-producing established reserves in Alberta including the Suffield Block.

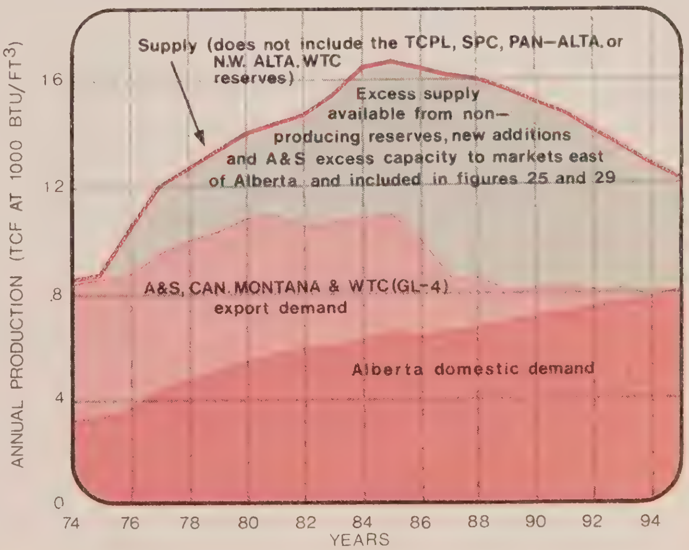
c) Reserves additions forecast for Alberta.

Since reserves of gas committed to Alberta and Southern and Canadian-Montana are substantial, relative to their licensed export requirements and since Alberta removal permits stipulate that all Alberta requirements must be satisfied before gas can be removed from the province, all these requirements could be met throughout the forecast period. It is possible however that the exports licensed under GL-4 will not be met because of supply problems in specific fields named in the provincial removal permit.

The excess supply shown in Figure 27 results from Alberta and Southern capacity in excess of the firm requirements, and deliverability from non-producing established reserves and reserves additions in Alberta. The excess supply was assumed to be available to meet requirements East of Alberta.

Figure 28 illustrates the deliverability from Alberta and Southern's producing established reserves which is available in excess of its firm requirements, that is, currently authorized exports and domestic sales. The excess deliverability is assumed available to meet Alberta deficiencies or requirements East of Alberta and has been included in the Board's forecast.

Figure 27
NATURAL GAS SUPPLY AVAILABLE TO MEET ALBERTA REQUIREMENTS (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) NEB FORECASTS



NOTE: PRESENT SHORTFALL IN GL-4 NOT SHOWN

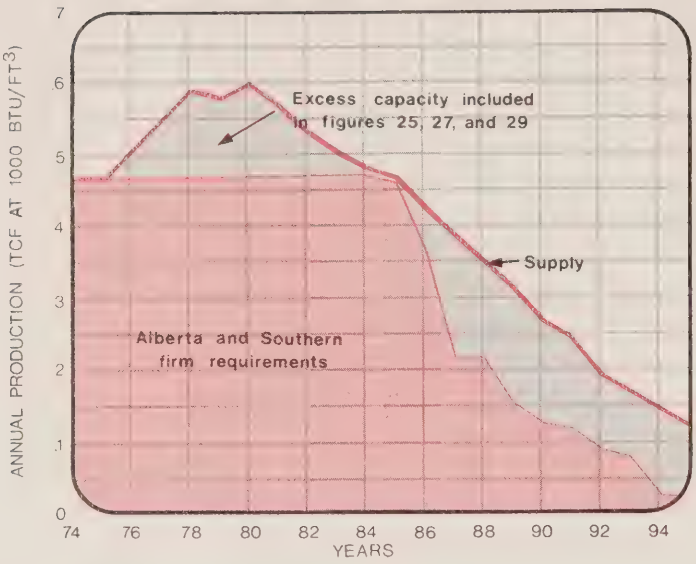
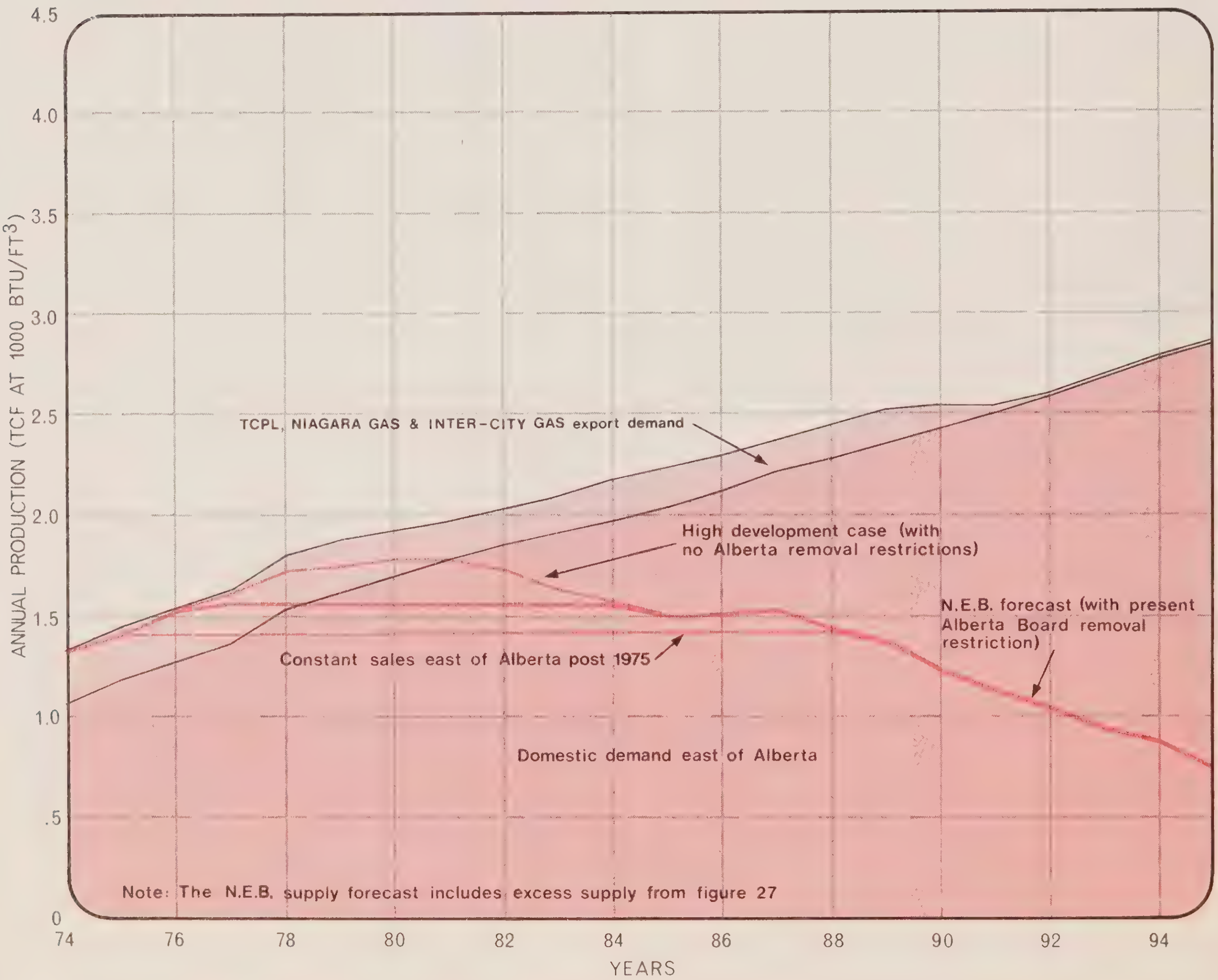


Figure 28

NEB FORMAT OF ALBERTA AND SOUTHERN'S EXCESS CAPACITY (CONVENTIONAL PRODUCING AREAS WITH NO RESERVES ADDITIONS) FROM PRODUCING ESTABLISHED RESERVES

Figure 29

NATURAL GAS SUPPLY AVAILABLE TO MEET REQUIREMENTS EAST OF ALBERTA (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) NEB FORECASTS



EAST OF ALBERTA

Figure 29 shows the supply available to meet requirements East of Alberta. The supply includes:

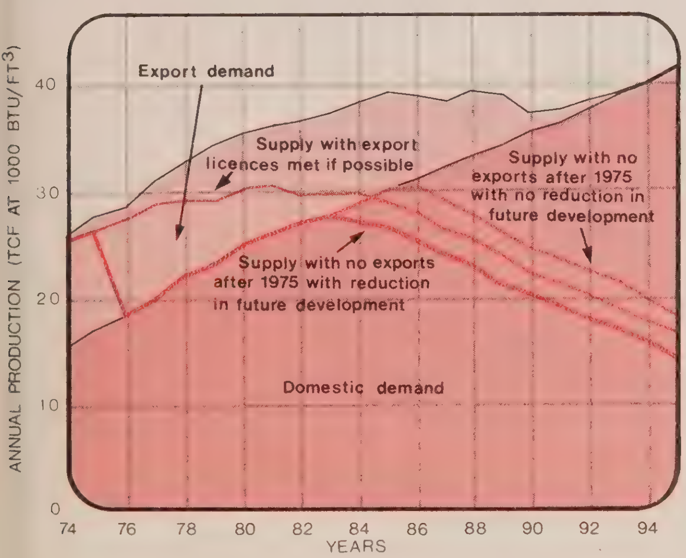
1) Producing established reserves in Alberta and East of Alberta supplying requirements East of Alberta.
2) Deliverability available in excess of the requirements in Alberta as developed for and illustrated in Figure 27.

Based on the Board's forecast of supply and demand, a deficiency will occur almost immediately and will continue to grow throughout the forecast period. The 1976/77 level of supply could be maintained until 1987 but the forecast supply will be unable to meet growing Canadian requirements beyond 1978.

At present, TransCanada does not have sufficient reserves contracted, nor sufficient fields named in its provincial removal permits, to maintain the existing level of domestic and export sales. As a result it has adopted a policy not to expand its transmission system until confident it has sufficient reserves contracted to support existing levels of sales for a reasonable period of time. The effect of this policy, if continued indefinitely, is shown in Figure 29.

The available supply East of Alberta if the High Development Case for deliverability were realized is also shown.

Figure 30
CANADIAN NATURAL GAS SUPPLY AND DEMAND (CONVENTIONAL PRODUCING AREAS WITH RESERVES ADDITIONS) EFFECT OF ELIMINATING EXPORTS POST – 1975



EFFECT OF ELIMINATING EXPORTS IN 1976

In view of the probable near-term inability of Canadian natural gas supply to meet total demand, including existing export commitments, and the inability of Canadian natural gas supply from the established producing regions to meet growing domestic demand beyond 1984, studies were made of the effect on deliverability in the 1980's and 1990's of eliminating exports immediately. In 1974, exports accounted for approximately 41 percent of total Canadian production of marketable gas.

The possible effect within Canada of completely eliminating exports in 1976 is shown graphically in Figure 30. Although it is possible to assess the impact of reducing the production rate from currently producing reservoirs relatively accurately, it is extremely difficult to predict the ramifications of such a dramatic change on the actions of the oil and gas industry in terms of connecting now unconnected reserves and in terms of exploring for new reserves. In calculating the supply with no exports after 1975 including reduced future development, as shown on Figure 30, it was assumed that the impact on the industry would be severe, and the deliverability available from now unconnected reserves and yet to be discovered reserves in the conventional producing areas would be reduced by approximately 50 percent. However, as this is highly conjectural the resulting supply assuming no reduction in future development is also shown. For comparative purposes the total supply with export licences met to be extent possible is indicated.

The analysis indicates that, if exports were eliminated immediately, deliverability would become inadequate to meet Canadian requirements sometime between 1983 and 1986 depending on the effect on new exploration and development activity of the shutting-in of developed natural gas deliverability. On the other hand if exports were continued to the extent that natural gas were available in excess of Canadian demand, new sources of supply would still be needed by about 1985 to meet Canadian requirements.

The realization of deliverability from reserves additions is dependent upon a strong and vigorous exploration and development program by the oil industry. If this program were slowed as a result of the sudden availability of considerable surplus deliverability and reduction in cash flow, as would result from complete cessation of exports, it could well be that the amount of gas available for consumption in Canada in the 1980's and 1990's would be reduced.

CONCLUSION:

1) The natural gas reserves in the conventional producing areas of Canada will not be adequate to meet both growing domestic requirements and currently authorized exports in the future.

2) In British Columbia, requirements including exports by Westcoast cannot be satisfied at this time and the situation is not likely to improve materially until Frontier gas becomes available.

3) In Alberta, requirements (including currently licensed exports by Alberta and Southern and Canadian-Montana) could be satisfied throughout the forecast period. It may not be possible to satisfy exports by Westcoast under GL-4 because of supply problems in the specific fields named in the Alberta removal permit. If the forecast reserves additions materialize, if currently non-producing established reserves are connected, and if Alberta and Southern increases deliverability from its producing established reserves to the extent possible, substantial deliverability in excess of the Alberta requirements would exist that could be made available to markets East of Alberta.

4) Requirements East of Alberta (including exports by TransCanada, Niagara Gas Transmission Limited (Niagara Gas) and Inter-City Gas Transmission (Inter-City) are unlikely to be met in a period beginning within the next year or two and continuing throughout the forecast period. If excess Alberta deliverability is made available East of Alberta it may be possible to maintain a constant level of deliveries from 1977 to 1984 from the conventional producing areas.

5) Pending the availability of frontier gas supplies, the extent of the forecast shortfalls in British Columbia and East of Alberta can be minimized by:

   a) Vigorous efforts by producers and transmission companies to maintain deliverability from currently producing reserves and to tie in unconnected reserves as quickly as possible.

   b) Active exploration to achieve the maximum possible reserves addition rate.

   c) Early and rapid development of the shallow gas reserves of southeast Alberta and southwest Saskatchewan.

   d) A concerted effort to increase deliverability in fields producing at rates-of-take less that 1:7,300.

   e) Establishment of a stable and healthy economic climate to encourage the above efforts by industry.

   f) Continued efforts by Alberta and Southern to make surplus deliverability available to markets East of Alberta.

   g) Authorization by the Alberta Board and the Government of Alberta of the addition of fields and pools to provincial permits affecting removals eastwards from Alberta to allow removal of newly purchased gas and excess Alberta and Southern deliverability.

   h) The development of further peak-shaving capability for Alberta utilities to improve their load factor and reduce the requirement they place upon permittees for gas in the peak season, and accordingly, to reduce the impairment of the peak season capability available for service to customers East of Alberta.

PROTECTION OF CANADIAN REQUIREMENTS

Compressor station near Rosedale, B.C.

(i) *Views of Submittors*

Submittors expressed one of two views on the suitability of the 25A4 protection procedure. A few considered the 25A4 procedure suitable. Most felt that it was not and that gas deliverability should be a prominent feature of any alternative protection procedure considered. Most submittors declined to offer any specific alternative procedure or formula but commented in general terms that:

a) protection should be established by considering both deliverability and demand;

b) exports should be conditioned to require that all Canadian demand be satisfied before exports;

c) the Board should consider supply and demand for all energy forms;

d) protection policies should be established on proven reserves and associated deliverability only;

e) protection policies should recognize the increased cost of future reserves;

f) existing licensed export commitments should be honoured;

g) short term exports to achieve specified goals should be permitted;

h) conservation should be encouraged;

i) lock-in of gas reserves should be avoided;

j) all gas beyond economic reach should be excluded;

k) the Board must carry out independent assessments of deliverability and demand;

l) the "surplus" concept should be dropped and exports considered on the basis of economic, social and national interests;

m) the Board should hold periodic supply/demand hearings;

n) Arctic reserves should not be considered until a pipeline is assured;

o) exports should meet price tests that incorporate review and adjustment conditions.

However, the Governments of Saskatchewan and Quebec presented greater detail than most submittors concerning the problem of protection procedures and formulae.

(ii) *Views of the Board*

The Board is required to determine the reasonably foreseeable requirements of natural gas for use in Canada and to consider for export only the surplus, if any, above this amount. Clearly a procedure for calculating or determining surplus is necessary.

The Board considers that any procedure envisaged should have as many of the following characteristics as possible.

1. It should be easily understood and applied.
2. It should incorporate gas deliverability rather than reserves in the supply considerations.
3. It should be flexible to respond to changing circumstances.
4. It should provide continuing protection for Canadian demand throughout any period of export.
5. It should provide incentive and encouragement to the gas industry.
6. Licensed export commitments should be satisfied to the extent possible.
7. It should reserve for Canadians any benefits from conservation restraints undertaken by Canadians.

However, attainment of the primary objective of an immediately usable and effective procedure, with the capacity for incorporation of all of these characteristics at this time, is not considered practical under prevailing circumstances. The Board recognizes the probability of insufficient near term supplies of gas to cover fully both the quantities of gas licensed for export and the quantities required to meet increasing Canadian demand and sees little possibility of this problem being resolved within the next few years. Since the Board intends to carry out its responsibilities under the Act to ensure that supplies of gas are available to meet Canadian demand before allowing gas exports, the real problem lies in the treatment of existing licences for the export of gas, rather than in theoretical schemes to determine conditions and circumstances under which additional exports of gas might be authorized.

Nevertheless, the Board recognizes that, for the guidance of both industry and the public, it is desirable to establish general principles which could form the basis of a surplus calculation procedure in the future.

The surplus calculation procedure would be based on gas deliverability and gas demand schedules developed for as far into the future as reasonable forecasting accuracy and data dependability will permit. The comparison of these two schedules will indicate the feasible volumes, rate and timing of exports. Unsatisfied volumes under existing export licences would normally have prior call upon any amounts of gas that may become surplus and available for export in the future by this procedure. All future export licences will be for short periods and will be conditioned in order that Canadian requirements for gas will be met, on a day to day basis, before any gas is exported.

Therefore, beyond stating these general principles, the Board intends to defer the development of a structured gas surplus calculation procedure until such time as its application can reasonably be expected to be needed.

It will, however, conduct and publish an annual review and reevaluation of the supply, demand and deliverability of natural gas.

ENVIRONMENTAL ASPECTS

The barren beauty of Frontier areas is illustrated in this photo of an ice formation on Melville Island

This section of the report deals with the views of the submittors and those of the Board concerning environmental aspects of natural gas supply, demand and deliverability.

(i) *Views of the Submittors*

The salient points made by submittors are summarized below.

It was stated that a comprehensive energy policy should include, among other things, consideration of environmental management factors; that the Board should include environmental protection as a factor in its interpretation of the public interest; that studies of environmental questions attendant upon energy policies should be carried out by the Board independent.of the views and recommendations of the petroleum industry; and that first priority for natural gas consumption should be its use for purposes that would improve air quality to protect public health and to minimize detrimental effects on equipment, property, and the quality of life.

Some submittors pointed out that natural gas is the "least polluting" of fuels and that it should, therefore, be conserved; that a "conservationist ethic" demands, among other things, a reduction in the environmental impact of energy resources development; and that the "surplus concept" would negate the benefits of reduced domestic demand resulting from conservation of energy resources.

A few submittors felt that the price and cost of energy are second in importance to sound ecological practices; that Canada even now, is being forced to turn to more expensive, risky, environmentally damaging and socially disruptive resources as cheap, accessible and assured supplies of energy are exhausted; that, in addition to considering the economic market price of natural gas, the Government should consider the future cost to society of any current environmental damage so that the "real" cost of future gas supplies can be determined. It was also stated that, in order to avoid long-term environmental impacts of persistent or slow-degrading petrochemical wastes and by-products, a "conservation tax" of \$1.00 per million Btu of thermal energy content should be levied against natural gas defined for use as feedstocks for the production of plastics or textiles.

Some submittors mentioned that increasing domestic and export demands and the resulting increase in production of Canada's finite sources of natural gas lead to the production of gas from ecologically delicate Frontier areas before technology has been developed to protect such ecosystems.

In regard to export of natural gas, it was the view of some submittors that environmental considerations, as components

of broadly-based criteria, must be applied to assure that any exports of natural gas are in the public interest; that such environmental considerations should include the rate at which Canada is forced into environmentally sensitive Frontier areas for gas supplies; a complete environmental impact assessment of all new exploration, development, and transportation schemes; a comprehensive cost/benefit analysis including "hidden social and environmental costs"; an analysis of alternative energy supply sources having less environmental impact; and the effects on the supply of "high quality, low polluting fuels" in Canada because of various levels of exports of natural gas. It was pointed out that all new and existing commitments for the export of natural gas should have to satisfy, among others, environmental criteria, and further that such exports should be determined "in terms of economic, social, and technological factors, not in terms of "surplus factor."

Some submittors observed that, because of the rapid depletion of natural gas, Canada is forced to turn to other energy sources such as coal gasification and nuclear power which were said to pose "more serious environmental problems". It was stated further that, because of many serious environmental problems associated with nuclear power, electricity now generated by natural gas must not be replaced by nuclear fuel.

(ii) *Views of the Board*

The submittors' environmental concerns reflect the growing interest of Canadians in energy/environment relationships. The Board recognizes the importance of taking into account relevant environmental factors in dealing with questions of natural gas supply, demand and deliverability. It is the Board's opinion, however, that many of the environmental issues raised by the submittors apply in the borad context of the energy/environment interface and can be dealt with more meaningfully in considering broad energy policy questions such as energy supply alternatives for Canadian requirements.

The Board has taken increasing account, over many years, environmental matters related to energy. The Board notes that the environmental concerns of some of the submittors relate to broad policy questions, including energy conservation, cost and price of energy, technological feasibility, export criteria, and energy alternatives.

With respect to broad policy questions, the Board agrees in principle that relevant environmental factors should be taken into account in developing a "comprehensive energy policy" for Canada. However it should be pointed out that the Board does not regulate all forms of energy resources nor all aspects of energy development. Nevertheless, the Board believes that environmental considerations could still be applied quite effectively in determining the supply and requirements of natural gas in relation to demonstrated constraints respecting the protection of the environment. The Board notes that policies and standards respecting environmental protection requirements have impacts on energy supply and consumption, and may result in significant additional use of energy.

On the subject of energy conservation, the Board notes that the Office of Energy Conservation, Department of Energy, Mines, and Resources, and the Science Council of Canada, among others, are studying the ways, means and potential results of implementing energy conservation measures according to end-use sectors. Such a program of energy conservation, introduced recently in the House of Commons, is enabling the Government to reduce energy requirements for its facilities and to educate and urge citizens to do likewise.

Canada also actively participates in the efforts of international organizations, such as the Organization for Economic Cooperation and Development, in the study of energy management policies and options including conservation. The Board believes that judiciously applied conservation policies and concerted actions of implementation thereof would not only provide for minimization of adverse environmental impacts but also result in certain environmental benefits.

With respect to cost and price of natural gas, the Board, while agreeing with the principle of "internalizing social costs", notes that tangible data and reliable methodology have yet to be developed before such costs can be truly reflected.

In regard to the adequacy of environmental technology for energy development in the ecologically delicate Frontier areas, the Board notes that the importance of research for environmental protection is well recognized by governments and industry. Federal and provincial governments as well as industry are doing substantial amounts of research on environmental effects and control technology in regard to energy development in Frontier areas. It is the Board's view that, since developments of natural gas sources in such areas would require new pipeline transportation facilities, adequacy of environmental protection can be examined at public hearings on applications made to the Board. Environmental impact assessments have been or are being made by government and by industry. The Board, as at present, will require from applicants for certificates to construct and operate facilities for natural gas transportation environmental statements as follows: a description of the environment existing prior to the construction of the physical facilities; statements on probable environ-

mental and social effects expected to result from building and operating the facilities; statements on plans, methods, and procedures to control, minimize or avoid undesirable environmental and social effects of building and operation the proposed facilities.

Social needs and environmental protection requirements can be examined on a case by case basis with respect to transportation aspects of natural gas development over which the Board has jurisdiction. In respect of the exploration for and production of gas resources, responsibility lies in other hands but there is every reason to believe that careful consideration will be given to environmental and social factors.

The Board is fully cognizant of the importance of reserving sufficient quantities of "low-polluting" fuels to meet the foreseeable Canadian requirements so that appropriate environmental quality standards may be maintained. The Board also notes that all levels of governments are concerned about controlling pollutant emissions and other waste discharges from power plants and other industries using fossil fuels or their derivatives, and that the Federal Government and several provincial governments have recently passed legislation enacting air and water quality objectives and standards. There is every reason to believe that as technology becomes available standards will be promulgated by all levels of government to control pollutants and waste as may be required in the public interest.

CONCLUSIONS & RECOMMENDATIONS

TransCanada Pipelines Limited, station 17, Regina, Saskatchewan

THE SHORTAGE IN SUPPLY

The actual and potential shortage until Frontier gas is connected, if and when adequate reserves are developed, results from two factors:

1. a lack of adequate growth in deliverability resulting from low finding rates and from a lack of incentive for producers to explore for and develop new reserves because of inadequate and uncertain netback. Producers have moved drilling rigs and personnel to the United States and other areas where opportunities at this time appear to be more attractive. The decline in exploration and development activity starting two or more years ago is now being reflected in fewer reserves being available to maintain deliverability. There has been an impairment in deliverability from large gas fields in northern British Columbia; and

2. a high rate of growth in demand in the Canadian market, partly caused by underpricing of gas in relation to alternative fuels. The growth East of Alberta in the past two years would have been greater but for the inability of TransCanada to obtain removal permits from the Province of Alberta and of distributors to contract for the desired supplies of gas.

Action to ameliorate the situation is likely to be needed in relation to three factors, namely, deliverability, domestic demand and existing export licences. Of these, improvement in deliverability including development of additional reserves to the extent feasible is the most attractive, since curbing domestic demand below levels which would result from Canadian pricing, conservation, and industrialization policies is not in keeping with the intent of the National Energy Board Act, and reducing exports could have serious consequences for United States' consumers of Canadian gas.

DELIVERABILITY

Improving deliverability is a complex national problem requiring the cooperation and coordinated planning of producers, gathering and transmission companies and distribution utilities, as well as the governments of producing and consuming provinces and the federal government. Furthermore, short term improvements will have to come from gas already found, but there is a lead time generally of about three years between the initiation of development activity and the delivery of the gas in the market place. It therefore seems imperative to mobilize a concerted effort to bring about appropriate action if any significant improvement in deliverability is to be

achieved in the remainder of the 1970's. If Frontier gas were connected — assuming adequate reserves are discovered and suitable transportation arrangements made — the need for and reliance on improved deliverability of gas from the Western Provinces would be reduced after that date.

PRICES, ROYALTIES AND TAXES

An essential component of a solution to the problem of deliverability would appear to be a known system of pricing and a stable system of royalties and taxation adequate to provide producers with the incentive to carry out vigorous exploration and development programs. Despite the recent clarification by the producing provinces and the federal government of the rates of royalties and taxes, uncertainty still appears to pervade the producers' minds. Clarification of the long term pattern of field pricing, royalties and taxes is a vital element in determining future producer netbacks — the key to investment decisions by producers.

The recent changes in Alberta royalties and federal taxation provide clearer indications to the producers of the impact of these costs. What is less certain is whether the many producers who make decisions having an impact on future deliverability regard these recent changes as adequate without clarification of short and long term pricing policy.

In British Columbia the prices offered by the British Columbia Petroleum Corporation for both new and old gas may stimulate some activity but are not likely to be adequate to bring on the level of exploration and development required to offset the impairment in deliverability of the Westcoast system.

For Canada as a whole, evidence at the Hearing clearly indicated that even immediate implementation of pricing of natural gas at full parity with competitive fuels might bring relatively little short run improvement of deliverability, although it would encourage the development of reserves both in the Western Provinces and in the Frontier areas in the 1980's; it would also have an inflationary impact on the Canadian economy.

Further idscussion on the pricing of natural gas is set forth later in the report, but in the Board's view, immediate introduction of full parity pricing linked to international oil prices cannot be regarded as an effective solution to the problem of improving deliverability in the 1970's.

CASH FLOWS FOR REINVESTMENT

A more complex problem is the concern of the producers with the cash flows necessary to maintain an adequate inventory of oil and gas reserves to sustain deliverability in the face of higher royalties, changes in taxation, the high rate of inflation as it affects the oil and gas industry, the higher cost of finding the remaining reserves in the Western Provinces, and the still higher costs in the Frontier areas.

As a preliminary opinion, the Board doubts that cash flows available to companies are sufficient to develop an adequate reserves base to meet growing Canadian needs. For example, the present Alberta royalty on field prices in excess of 36¢ per Mcf is approximately 50 percent for old gas and this royalty is not deductible for federal tax calculation. On the other hand, the Alberta Petroleum Exploration Plan of December 1974 improved the netback to the producer.

The large proportion of the revenue from higher prices accruing to governments from royalties and taxes does not, in the Board's opinion, leave producers with sufficient cash for exploring and developing high cost reserves in a way which will maintain the inventory of reserves necessary for continuing maintenance of deliverability.

Given a national goal of some degree of self-sufficienty in energy, and the share of income from the industry going to governments, a program of investment of public funds in the oil and gas industry seems essential. Syncrude is a good example.

ALBERTA AND SOUTHERN PURCHASING

Another situation which could aggravate the shortage in the Canadian market results from the aggressive and successful gas purchasing activities of Alberta and Southern Gas Co. Ltd. Over 85 percent of Alberta and Southern sales are to the Northern California market. Alberta and Southern has filed an application for additional exports but has not asked the Board to proceed with it at this time; however, it had been buying gas to support its application. Alberta and Southern's reserves under contract are now 9.7 Tcf compared with remaining quantities licenced for export of 5.1 Tcf. The difference of 4.6 Tcf are reserves which, under the Board's 25A4 formula, would be assumed to be available for the protection of the Canadian market. Obviously, in the present circumstances, they are not available for this purpose. Alberta and Southern indicates it needs these reserves because of uncertainty as to the priority claims of Alberta utilities and the need to maintain the future deliverability of its export commitments.

Alberta and Southern is continuing to buy gas in 1975, aided to some extent by a higher payment to producers than other buyers can offer because most of its gas is sold at the export price of $1.00. Alberta and Southern stated that the higher payment of 27¢ per Mcf, when compared with payments to producers providing gas to the TransCanada system, results, after deducting royalties and taxes, in only a net increase of 3¢ per Mcf to the producer. In any event, the Board is recommending that this flow-back system be changed.

Alberta and Southern, it should be noted, has provided some relief to Westcoast Transmission Company Limited to help alleviate its shortfall in deliveries to the Pacific Northwest. In addition, Alberta and Southern is also making some deliveries available to TransCanada on a "best efforts" basis; that is, to the extent it can do so without impairing Alberta and Southern's contract obligations to its export customer. Alberta and Southern has also had to meet new demands by Alberta utilities and production from some of its existing fields has been impaired. The exceptionally high reserves protection by Alberta and Southern of its export contracts, in contrast with the impaired deliverability on the TransCanada system which serves Canadian needs East of Alberta, is clearly a problem requiring resolution in that it ties up reserves which could otherwise be available to meet Canadian requirements.

PAN-ALBERTA

The role of Pan-Alberta Gas Ltd. is also important in relation to the potential shortage in the 1970's. Pan-Alberta has purchased gas under six-year contracts with high rates of deliverability and, in many cases, from marginal pools which might not otherwise be connected. Deliverability of the gas in the 1970's would appear to complement the potential arrival of Frontier gas about 1980. Based on knowledge of Pan-Alberta's current contractual situation, the Board estimates Pan-Alberta might deliver up to the following quantities of gas:

	Bcf
1975	30
1976	50
1977	70
1978	60
1979	50
1980	45

The foregoing includes 14.6 Bcf per year under an initial contract with Gaz Métropolitain under which some gas is now being delivered. Other contracts are indicated to be near completion. There is still some doubt concerning the ability of Pan-Alberta to deliver the volumes indicated in the previous table, and there have been delays in deliveries to Gaz Métropolitain as well as in concluding further contracts. These delays have been caused by pricing problems as well as by the preference of the Ontario Government and Ontario distributors to continue to buy their gas from TransCanada.

There is also a question as to TransCanada's willingness to carry Pan-Alberta gas which is related to the broader problem of Alberta's actions in not approving removal permits to TransCanada even though TransCanada is buying new gas and renegotiating the price of old gas on the basis of the award under the Alberta Arbitration Act. Nevertheless, in the Board's view, it is important that these problems be overcome quickly so that the gas now under contract to Pan-Alberta as well as gas under contract to TransCanada, but not covered by removal permits, can contribute to the alleviation of the impending shortage of natural gas.

EFFECT OF EXPLORATORY ACTIVITY IN THE UNITED STATES

A further problem relates to the competition of the United States in particular, and the energy-short world in general, for drilling rigs, skilled personnel and investment funds. The uncertainty and lack of economic incentive on the Canadian scene in the past two years and the large exploration and development program underway in the United States under more favourable incentives, have caused an exodus of equipment, men and money south of the border. For example, at the present time, royalties in the United States are between 12.5 percent and 16.7 percent and are deductible for tax purposes, compared with royalties of up to 50 percent in Alberta — non-deductible for federal tax purposes — and not particularly attractive field prices, net of royalties, in British Columbia. The price of new gas in intra-state sales in the United States is relatively attractive. The Board therefore recommends that federal and provincial governments review the adequacy of prices, royalties and taxes and the resulting netback to the producer in relation to the incentives needed in Canada to offset the pull of exploration opportunities from the larger United States market. Such a review would necessarily need to cover oil and gas because of the interrelatedness of the exploration for these hydrocarbons.

INCENTIVES

In the Board's opinion, incentives should be particularly aimed at the specific segments which can make the greatest contribution to the solution of the problem, namely, the 2.8 Tcf of unconnected, uncommitted reserves available in Alberta, the 1.0 Bcf in the Suffield Block, and a further 1.0 Tcf of unconnected, uncommitted reserves in British Columbia, as well as any improvement which can be made in deliverability from presently contracted and connected reserves.

Evidence at the Hearing suggested that some improvement in deliverability could be achieved from already connected reserves but that it would not be prudent to rely on a quick and dramatic increase from this source. This is because of the time lags involved, and the fact that existing production is often tied to specific contracts between private parties. Incentives of various kinds will have to be designed in order to induce the desired improvements in deliverability.

As a starting point, better information is needed, for planning purposes, on the amount of gas which producing provinces expect to authorize for removal from the province for each of the next five years. The industry will need to coordinate the planning and execution of:

a) infill drilling;

b) connection of new reserves;

c) development of processing plants;

d) new gathering systems;

e) expansion of transmission systems; and

f) development of greater storage facilities available to distributors.

Some of the investments may have a comparatively short life and cannot be expected to be more than marginally attractive.

Incentives are needed to embrace some or all of the following features:

1) acceptance by distributors and consuming provinces of higher prices;

2) possible advances or prepayments by distributors and by transmission companies;

3) lower royalties for new gas (Alberta and British Columbia have instituted such differentials but they may need further adjustment);

4) faster write-off for tax purposes of expenditures for gas plants and gathering systems with a short life;

5) relaxation by producing provinces of their protection requirements if it becomes apparent that there are good prospects of future availability of Frontier gas; and

6) rate designs to encourage the efficient use of gas; for example, the avoidance of "dumping" of valley gas (gas transported in the system when spare capacity is seasonally available) in the summer.

DOMESTIC DEMAND

Sales of natural gas in Canada until recently have been growing at a rate of 10-11 percent per year partly because gas has been significantly underpriced in relation to other fuels. Gas has therefore not been used in all cases in a way compatible with conservation of a scarce non-renewable resource.

PRICING

Considering first the pricing of natural gas, in the medium term, as indicated earlier, full parity value based on world oil prices would not significantly improve the deliverability of natural gas over that provided by a more modest increase in price. For example, evidence was given that an increase in the field price to 80¢ to $1.00 per Mcf would be sufficient to induce the connection of gas which could improve deliverability in the 1970's. This more modest price increase would avoid some of the adverse inflationary consequences of full parity. In the longer run, prices will have to rise to the level necessary to develop whatever resource base is available under reasonable economic conditions. Nevertheless, movement towards higher prices need not preclude the continuation of a two-price system, one for exports and one for sales in Canada, nor prevent Canada, in particular the producing provinces, from taking advantage in industrial development of Canada's relatively favourable energy base.

If gas should become available from new areas in quantities more than adequate to meet Canadian requirements, the case will be even stronger for using this resource primarily to supply Canadian requirements at a price consistent with the costs of exploration and delivery. The Board therefore does not accept the argument of those submittors advocating full parity pricing, including premiums for form value based on OPEC oil prices, since this would do little to resolve the prospective

medium term shortage, would price all Canadian gas at a level in excess of U.S. levels, thereby impairing Canada's competitive position, and would result in a curtailment of Canadian demand in the 1980's when gas may be in ample supply. Such a policy does not appear to the Board to be in the Canadian public interest.

Agreement between the federal government and producing and consuming provinces on future prices is urgently needed as is agreement on the share of the revenue to accrue to the producers, so that the industry in general can proceed in planning its future courses of action and in making investment decisions with some assurance as to the regime of prices, taxes and royalties likely to prevail in the domestic markets over the next three to five years.

The Board believes that the substantial underpricing of gas in the domestic market relative to the price of other fuels should be progressively eliminated and the price should rise to a level sufficient to induce exploration for and development of major new sources of supply. Therefore, the Board recommends a pricing policy phasing upwards towards commodity value over about a three-year period, using in the 1970's, the equivalent Btu price of Canadian crude oil in the Toronto market as the yardstick of commodity value in this phase-in period, and reassessing the situation in the light of circumstances as they develop.

CONSERVATION

The need for conservation in the use of natural gas is implied in the recognition of it as a scarce non-renewable resource. The federal government has already launched an energy conservation program seeking the voluntary cooperation of Canadians, and more comprehensive programs are being developed. Much of the jurisdiction relating to conservation measures belongs to the provinces, and the Board is aware of conservation programs underway and being studied in several of these provinces. Conservation measures, in the Board's view, should increase the supply of gas which would be available for future use in Canada.

MAJOR NEW REQUIREMENTS

An important aspect of the Canadian demand for gas is that major new requirements which could not be foreseen a few years ago are now developing. These include the use of natural gas as feedstock for the petrochemical industry, the expansion of the gas-based fertilizer industry, and the new opportunities for natural gas in the Québec market for process use in the steel industry.

The new opportunities for chemical industry developments in Canada arise in part from the shortage of oil and gas in the United States and because planned chemical industry developments in the Middle East are likely to take some time to come to fruition. The opportunities include the production of ethylene, ammonia, methanol and their derivatives. These opportunities coincide with the objectives of Alberta to diversify and industrialize its economy.

The Board views with favour the rapid further development of an advanced petrochemical industry aimed largely at the domestic market, but also at export markets, provided there is some assurance of the longer run viability of these plants in the face of potential competition from Middle East production units based on lower cost feedstocks. The Board believes, however, that controls are needed over the export of basic petrochemicals derived from natural gas as a feedstock, particularly during the period when a potential shortage of natural gas for use as fuel in Canada may exist.

In Québec, until recently, natural gas could not compete effectively with oil because of the low price of imported oil and its penetration has been restricted to five percent of the energy market. The relative price of oil and gas has reversed but the Québec distributors have not been able to secure the gas they need to meet growth in existing market areas or to develop new markets, because of the difficulty in contracting for new supplies of gas.

A further problem, discussed later, relates to transporting the gas to the province. Québec desires more of this premium fuel, both for residential use and to develop its industrial base, including the use of gas in industrial processes and for reasons of security of supply. Ontario and Manitoba also have not been able recently to obtain supplies of gas sufficient to meet potential demand.

EFFECT OF FLOW-BACK FROM HIGHER EXPORT PRICES ON GAS PURCHASING

When export prices were increased to $1.00 per Mcf, the federal government required that the benefit from the higher export prices should flow back to producers — except in B.C. where it would flow initially to the British Columbia Petroleum Corporation in respect of those producers selling gas to it. The initial scheme, which the Board indicated might need to be modified, caused the increased funds to flow back to the producers serving each group of licences. This has meant that producers selling to Alberta and Southern where the gas is shipped almost wholly to export markets, receive a much higher netback than producers selling on the TransCanada sys-

tem where at least 60 percent of the gas is sold in the domestic market. This is inequitable and inhibits gas being purchased for the domestic market. The Board is proposing to modify the export flow-back scheme on the basis that Alberta producers should receive the same flow-back for each Mcf of gas sold.

TRANSMISSION OF GAS BY TRANSCANADA PIPELINES

TransCanada Pipelines has been the major buyer of gas for utilities east of Saskatchewan; some time ago it stated it was willing to carry gas on a contract basis for others. More recently, because of its assessment of the impending impairment of deliverability on its system in relation to its contractual obligations to domestic distributors and export customers, it has refused to enter into further transportation contracts to carry gas for others. At the Hearing, TransCanada indicated that its present policies were based primarily on meeting its contractual obligations to domestic and export customers. It recognized some obligation to renew contracts to Canadian distributors when they expired, but its exact position on this point was not clear.

TransCanada stated that, following this policy, it was buying natural gas both in conventional and Frontier areas only to maintain deliverability, but indicated that at this time it estimated that all gas in Alberta surplus to that province's needs would be required to maintain deliverability on its system in the 1970's. Although it had earlier indicated to distributors that they should negotiate directly with producers for natural gas to meet growth in their own markets, TransCanada now reluctant to carry additional gas for them until it has acquired sufficient gas itself to restore the deliverability on its system.

Part of TransCanada's problem appears to stem from the reluctance of the producers and the Alberta Government to accept TransCanada as the sole buyer of gas for Eastern Canadian utilities, while at the same time, the Government of Ontario insists that TransCanada should be the sole buyer. These attitudes may have had relevance when gas prices were established by arm's length negotiation between private parties. That situation has virtually disappeared with pricing being determined in effect by decisions under the Alberta Arbitration Act. If prices are to be established by government, as seems likely, the producers' netback will not be affected by the identity of the buyer nor indeed by the number of buyers for a given market. In these circumstances, if it is more efficient for TransCanada to the buyer, and if Eastern distributors and the Ontario government wish to operate this way, the Board can see no disadvantage to producers as compared with direct purchase by distributors.

It is understandable in this difficult and complex situation that TransCanada should refuse to enter into new contracts while faced with the threat of impairment of its ability of fulfill existing ones.

From a Canadian public interest point of view, the present situation has the result that facilities will not be provided to meet growing Canadian needs for natural gas.

This situation could be improved if the pricing issue with Alberta is resolved and Alberta releases the outstanding removal permits. The attitude of TransCanada will also be affected by the treatment of existing export commitments recommended by the Board. Nevertheless, it is the Board's view that reasonably foreseeable requirements of Canadians should be supplied and that transmission facilities should be built to deliver the gas under appropriate safeguards to the transmission company.

The Board anticipates that TransCanada will wish to reconsider its present policy in the light of the Board's statement of intent to condition export licences in order to ensure that Canadian requirements are met and its recommendation, discussed later, to create powers of allocation in relation to natural gas. These two actions will place a new perspective on TransCanada's contractual obligations and, provided the company's financial integrity is not impaired, it is anticipated that TransCanada will provide the services expected of a pipeline transportation company in relation to approved Canadian requirements for service.

EXISTING EXPORT COMMITMENTS

Section 83 of the Act prescribes certain tests to be applied by the Board under an application for a licence. In particular the Board must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada.

Under Section 17(2) of the Act the Board may change, alter, or vary a certificate or licence issued by it, but no such change, alteration or variation is effective until approved by the Governor in Council. While this section has never been applied in relation to licences for exports of natural gas, circumstances may require the Board, in the public interest, to modify such licences and the conditions applicable to them.

These provisions of the Act must have been in the contemplation and knowledge of the parties at the time contractual commitments were made. In the view of the Board it is contrary to the provisions and the intent and spirit of the Act

that contractual obligations permitted under export licences should continue to be fulfilled under circumstances in which Canadian requirements for use of Canadian natural gas in Canada cannot be met. The applicable provisions and the powers of this Board under the Act indicate that the requirements for gas for use in Canada must be protected and the terms and conditions of licences can and, in circumstances such as now exist, should therefore be varied.

The Alberta Government conditions removal permits from the province to require that priority be given to the needs of Alberta utilities. This effectively ensures that Alberta consumers obtain the gas they need, including growth above present levels of demand, irrespective of contractual obligations to users outside the province.

It is also interesting to note that Alberta removal permits are conditioned as to the fields from which gas can be taken; similarly existing Canadian export licences will be regarded as conditioned to be limited to gas from currently producing fields and no Frontier gas will be allowed to be exported to meet existing licences without explicit Board approval.

At the present time, the Province of British Columbia does not have a system of removal permits. However, in the present Hearing, the B.C. Energy Commission stated that B.C. gas users would not be limited to their present contractual entitlements even if this meant that contractual obligations to export customers could not be fully met.

Saskatchewan is a net importer of gas and there are indications that applications to remove gas from the province would not be likely to be approved. Each of the three Western producing provinces has indicated that it has taken or is taking steps to protect consumers. Consumers in Manitoba, Ontario and Québec are, however, left without adequate protection.

The existence of the potential shortage makes it most unlikely that applications for licences for new exports of gas, before the connection of Frontier gas, could be granted. Within the constraints of the prospective shortage, the Board will, however, seek to the extent possible and in compliance with the Statute, to avoid or mitigate hardships among export customers isolated from substitute supplies of energy.

The present Canadian situation is, to some estent, understood in the United States as shown by the following quotation from page 19 of the National Gas Survey, Volume 1, "A Time for Decision and Action", preliminary draft published by the United States Federal Power Commission, February 1975.

"It is now clear that we cannot rely on Canada over the near term to continue to serve American export markets for either natural gas or oil at historic prices and levels of service. The potential for future natural gas deliveries from Canada to the U.S. is related to the extent to which Canadian reserve levels may be developed which are in excess of Canadian requirements and to the mutual advantages which may accrue to each through the construction of new oil and gas transportation systems from the as yet undeveloped Canadian frontier areas".

CANADIAN REQUIREMENTS AND EXPORTS

It is the view of the Board that reasonably foreseeable requirements for gas for use in Canada consistent with the pricing, conservation and industrialization policies of Canadian governments, must be given priority over existing export commitments. In this regard, several export licences have a cumulative feature so that gas not exported in any year can be exported in subsequent years. The Board will recommend that the remaining licences not having such a condition be made cumulative so that if an impairment does occur but adequate gas later becomes available, the quantities in the licence could be restored. If licences were to expire before the maximum authorized quantity could be exported, consideration could be given to making up any shortfall in the awarding of new licences, if and when new exports become possible.

NEED FOR ALLOCATION

The Hearing made evident that there is still uncertainty about the size and timing of a future shortage and the effect on peak-days will be more acute than on annual deliveries. Also there is no existing arrangement to ensure that reasonable demands for gas in the non-producing provinces are met, and unreasonable demands discouraged and that equity between the domestic and export markets is achieved. It is also apparent that the price mechanism can give only limited assistance in resolving these problems. While it is not yet clear whether these problems will be relatively light or severe, it is evident that there are, at present, inadequate mechanisms for dealing with them. The Board therefore will be recommending that allocation powers be created to cope with the situations outlined above.

PLANNING

The foregoing review of the problems of coping with the shortage of natural gas in the 1970's has highlighted the complexity of the issues, their national scope and the interrelation among actions by producers, gathering, transmission and distribution companies, and governments.

A coordinated approach is needed if the adverse impact of the shortage is to be minimized, yet no adequate planning mechanism exists to provide a forum for the various parties involved to come together and work out a comprehensive plan of action. A start is being made within the Canadian Gas Association but its forum needs broadening so that it embraces producers, gathering, transmission and distribution companies, consumers, as well as provincial and federal governments. The Board will be recommending the creation of such a body.

RESOURCE DEVELOPMENT AND MANAGEMENT IN THE 1980's

THE NEED FOR GAS

The evidence is clear that if existing export commitments are to be met, new sources of supply will be needed for use in Canada at an early date. The uncertainty as to the extent of the shortage in the 1970's and the fact that major developments for using gas in Canada, such as petrochemicals, may well have to be deferred pending the availability of new sources of gas both point to the prudence of connecting new sources of gas at an early date. Even if existing export commitments are not met, new sources of gas will be needed by Canadians by the mid-1980's.

DEVELOPMENT OF THE RESOURCE BASE

Since there is a demonstrable need for new sources of supply a strategy is needed on the development of the resource base. It is difficult to formulate such a strategy without adequate information and improvement of the knowledge of new sources of supply and alternative options.

The evidence indicated that there is still inadequate information to appraise the size of the Beaufort-Delta and High Arctic resource base. The reserves discovered are relatively small and estimates of the potential cover a wide range. A perspective on the role of Frontier gas cannot be achieved until more information is available. Several producers mentioned the urgent need to clarify jurisdictional matters in offshore areas, and the regulations relating to leasing and royalties in all Frontier areas, in order to stimulate exploration activity.

OPPORTUNITIES FOR CANADIAN USE OF NATURAL GAS

There was some evidence that if Frontier gas were connected to markets it would be likely to flow at first in quantities which would be difficult for the Canadian market to absorb immediately. Yet, on the other hand, there are additional major new uses as well as possibilities for extensions of existing markets for gas in Canada. It would appear that an opportunity exists for Canada to use this energy and feedstock supply to further its own development. Coordinated planning by the federal and provincial governments and industry is vital if full advantage is to be taken of the potential surge in supply which could result from successful Frontier developments.

SURPLUS TESTS – NEW EXPORTS

There was considerable but inconclusive discussion of whether new exports would be a necessary component of a pipeline project to connect Frontier gas. This question will be resolved only when applications are heard and decisions rendered.

The Board's view, given earlier in this report, is that any new exports must be relatively short term and conditional on Canadian needs having continuing priority. A forecast of "reasonably foreseeable requirements for use in Canada" can be overtaken by actual events not adequately foreseen; there is an obvious need to avoid repeating the present difficulty in which gas needed in Canada is committed to export on long term contracts.

There was virtually unanimous agreement among the participants at the Hearing that the Board's 25A4 formula, designed for protection of Canadian requirements, is inadequate in today's conditions to ensure protection of Canadian markets. More emphasis will have to be given to deliverability and to ensuring that Canadian requirements are met on a continuing basis. In addition, the complexities and uncertainties related to Frontier gas require that the Board maintain some flexibility in its attitude to applications for export licences.

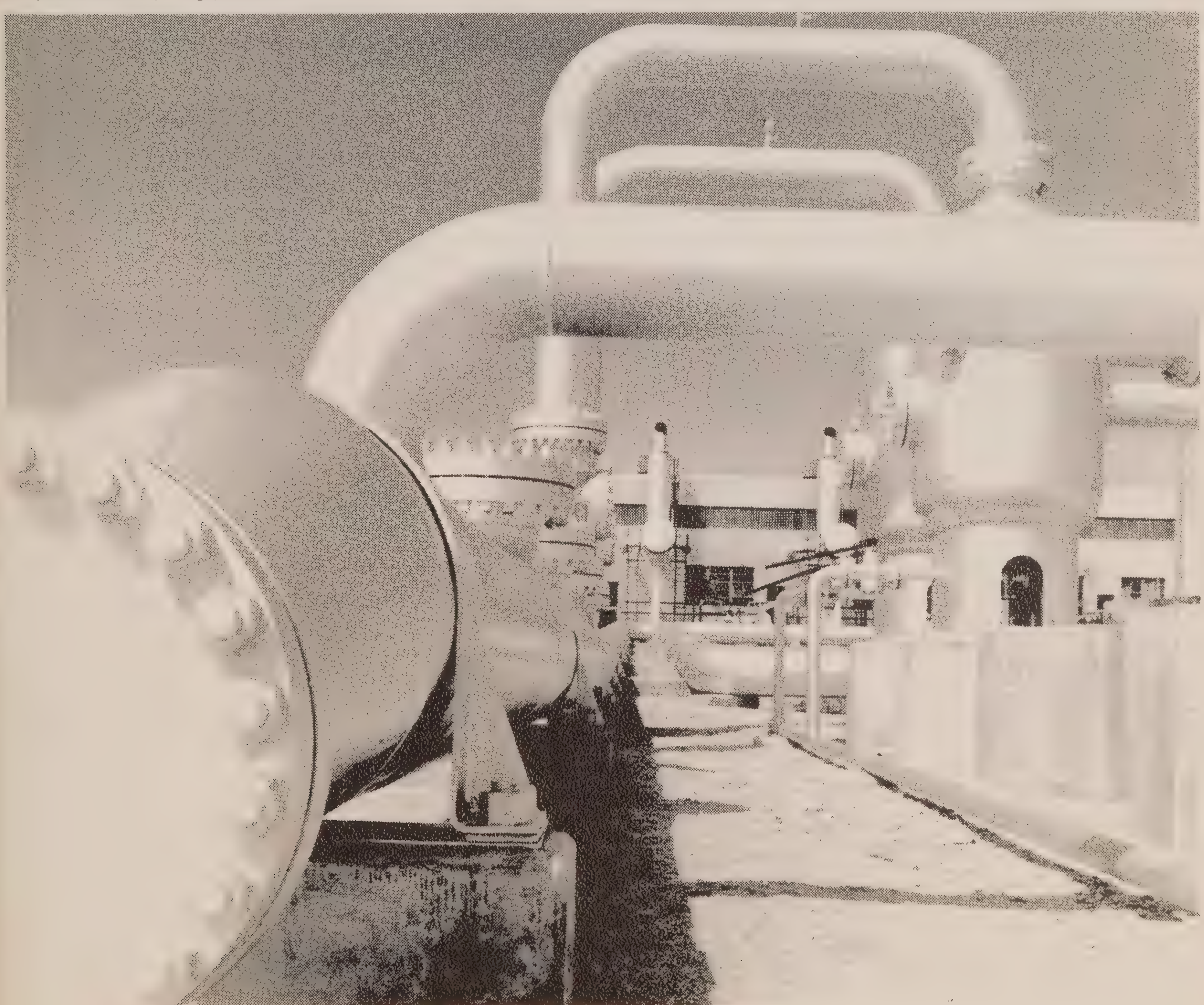
RECOMMENDATIONS

It is probably not possible to avoid a shortage even with a rare combination of optimum decision-making by producers, gathering and transmission companies, distributors, and provincial and federal governments; it would not be prudent to assume this optimum will be achieved. Nevertheless it is the hope of the Board in making its recommendations that the incentives for all parties to avoid the consequences of a shortage will be such that the use of any powers to allocate natural gas can be minimal.

The following recommendations are aimed at alleviating the impending shortage of natural gas in the 1970's, and at developing policies for the longer term when natural gas could once again be available in quantities such that some of it might become surplus to Canadian needs.

In relation to the shortage, the recommendations are of four types. First, there are proposals for improving deliverability; secondly, for raising prices in Canada which will have an effect on curbing demand and stimulating supply; thirdly, the Board recommends the creation of new powers to allocate gas in Canada; and fourthly, the Board indicates action that will be taken to condition existing export commitments so that priority can be given to Canadian demand.

Compressor station, Image, Ontario



DELIVERABILITY

Improvement of deliverability must be achieved to the greatest practicable extent in alleviating the impending shortage in the 1970's.

The most important single step in this regard is the removal of uncertainty from the minds of producers and the assurance of a netback to them which will be adequate to stimulate exploration and development. The necessary actions would appear to include:

1) assurance by provincial and federal governments that the system of taxes and royalties, once established on a basis adequate to stimulate exploration and development, will remain in effect for a sustained period;

2) an appropriate field price in Alberta (including the netback from exports) in 1975 which, in the Board's view, would be adequate to induce greater deliverability would be in the range of 80¢ to $1.00 per Mcf. In this regard, it would be of assistance if governments endorsed the principle that the flow-back from higher export prices should be equalized for Alberta producers.

   It would be of assistance to the industry if governments could agree on a formula for pricing gas consumed in Canada over the next three to five years so as to provide the producer with sufficient assurance as to future prices in order that uncertainty in investment decisions could be reduced; there would then be less tendency to defer making them;

3) in the Board's view, the present schedule of field prices in British Columbia, where there is no explicit royalty, is unlikely to lead to a sufficiently vigorous exploration and development program and this will cause a continuation of the existing shortfall in deliverability. If this situation is to be improved, it seems essential that the B.C. Government should review its schedule of field prices in relation to those expected to prevail in Alberta and to the opportunities for exploration which now exist in the United States;

4) review by producers and provincial and federal governments of what further incentives might be needed beyond those identified above to encourage:
   (a) the early connection of discovered but not yet connected reserves; and
   (b) the maintenance and, where possible, increase of deliverability from reserves now connected;

5) assuming the domestic pricing issues have been resolved, it would in the view of the Board be in the public interest of Canada if the Alberta Government, in the light of the new circumstances prevailing, were to release the permits removal for TransCanada Pipelines already approved by the Alberta Energy Resources Conservation Board. It would be helpful to add removal permits to Alberta and Southern's permits so that gas under contract to that company can be more readily made available to relieve shortage East of Alberta. In addition, it would assist in planning measures to relieve the shortage if the Alberta Government were to make available annually a five-year forecast of deliverability, consumption in Alberta, and the quantity of gas which might be authorized for removal from the province.

PRICING

The Board's recommendations on pricing are intended to meet as equitably and fully as possible the interests of producing provinces and of Canadian consumers in such a way as to bring optimum advantage to Canada as a whole. The most appropriate pricing policy, when the bulk of production for use in Canada East of Alberta comes from one province, must recognize the interests of that province.

The Board recommends, for the purpose of conserving a valuable non-renewable natural resource and inducing exploration for the development of new supplies, that domestic prices of gas be phased in to commodity value — using as a major yardstick the Btu equivalent of the price of Canadian crude oil at Toronto — over about a three-year period.

The Board further suggests that the price of natural gas should be high enough when Frontier gas reaches markets to ensure development of the resource base for Canadian use. In the longer term, the Board recommends that consideration be given to maintaining a two-price system, one for domestic sales and one for exports, if future supply developments are such that Canadians and Canadian industrial development can take advantage of a favourable natural gas resource base. The price to Canadians should be cost related in the broad sense of being adequate to ensure further development in supply; the price for exports should be related to the cost of alternative energy supplies in the export market.

CONSERVATION

The Board endorses the programs of conservation being undertaken and proposed by federal and provincial governments and would hope to see them strengthened.

In this regard, the Board attaches importance to the absolute saving of energy, rather than merely encouraging gas users to convert to oil, the longer term supply of which may be equally or more uncertain.

NEED FOR ALLOCATION

The Board recommends enactment of legislation to provide for powers of allocation.

The purpose of the legislation would be to ensure that gas to meet approved foreseeable requirements for use in Canada is given priority over exports and that, to the extent that gas available for use within Canada is less than the total Canadian demand, the available supply is delivered on an equitable basis in relation to the requirements of the various provinces in which Canadian gas is consumed.

EXPORTS

The National Energy Board Act requires that Canada's energy needs be protected and permits the export only of surpluses in excess of "reasonably foreseeable requirements for use in Canada". It was never the intent that, should circumstances arise which could not be foreseen when a long term licence was issued, Canadians should be denied the right to use their own energy resource. Export licences, issued by the Board with the approval of the Governor in Council, authorize the export of "not more than" certain daily, annual and total amounts and are not a commitment to maintain the maximum permitted export levels.

The Board proposes to take appropriate action under Section 17 of the Act, for the purpose first, of inserting a condition in all existing export licences making the annual and daily entitlement conditional on approved Canadian requirements being met, and second, of making cumulative those licences which are not now cumulative. Consideration could be given to making up any shortfall in any new export authorizations if and when they may be approved.

The Board recommends to the Government that the Government exert control over the exports of first stage derivative chemicals produced from natural gas as a feedstock which are not now subject to control under the National Energy Board Act. This appears to be essential to safeguard Canadian requirements for natural gas to ensure development in Canada of the secondary and tertiary stages of the chemical industry. The Board controls the export of ethylene but does not have control over such gas-based materials as ammonia and methanol.

With regard to the calculation of surplus for purposes of disposing of export licence applications, the Board will henceforth make a case-by-case assessment of reserves and deliverability both when licences, if any, are issued and at appropriate subsequent intervals. This will include both a Canada-wide assessment and one based on each delivery system. All future exports will be conditioned so that Canadian requirements will have continuing priority.

It is clear that great reliance for Canada's future needs is being placed by many who made submissions to the Board on anticipated gas supplies from the Beaufort-Mackenzie areas and the Arctic Islands. Although the extent of reserves so far discovered in the Beaufort-Delta area and the Arctic Islands is still far short of the amounts needed to resolve all concern about future supply, the Board believes that Arctic or other Frontier reserves are likely to be developed more fully and does not recommend cessation of all natural gas exports at this time. In fact, cutting off all exports at once would extend our period of self-sufficiency only very marginally compared with phasing out exports, as necessary, to meet Canadian needs. See Figure No. 30 on page 72. The same figure shows that such a phasing process does considerably extend the time during which Canadian requirements can be met from non-Frontier sources.

If it becomes apparent that Arctic reserves will not materialize in significant quantities or if whatever reserves may be proven should not be connected to market, the government should then seek an arrangement with the United States under which any further Canadian exports, under existing licences, would be repayable in gas. Further measures may require consideration if the supply and deliverability situation does not materially improve.

PLANNING

The Board recommends that a committee or council with representatives from all sectors of the gas industry and provincial and federal governments be formed:

1) to study and advise upon means to reduce the impact of the impending gas shortage;

2) to study and advise upon means of using to best advantage the surge of natural gas expected to be available and when gas from Frontier regions is connected to markets.

The Board is well aware that the problems we face cannot be solved by any new arrangement for consultation and discussion. The differences of view in Canada reflect real differences

in interests; nevertheless such a committee or council might provide a clearing house where a common understanding of facts and of viewpoints could be sought and perhaps achieved, where ideas could be exchanged and tested, and where priorities and means of meeting problems could be assessed. Such a council could not of course commit governments or corporate entities, but it could make available to governments and corporations informed advice and perhaps useful recommendations springing from an agreed basis of facts and a broadly considered assessment of options. It would supplement but not replace the many channels of communication which are necessary in the political, official, regulatory and business spheres and could be useful in speeding up the process of communication, feed back and synthesis which is necessary to deal with a set of problems so intricate as that now apparent in relation to the natural gas industry.

Chairman

C. G. Edge

Member

J. Farmer

Member

An unusual effect is achieved when a "posterization" technique is used on a night view of an Imperial drilling rig.

Canadian Natural Gas

Supply & Requirements

National Energy Board
February 1979

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Recital and Order of Appearance

A public inquiry in the matter of the supply of and the domestic demand for natural gas, authorized exports of gas, and the method of determining the volumes of gas which may be surplus to the reasonably foreseeable requirements in Canada, and related matters, held pursuant to Part II of the National Energy Board Act.

File: 1122-2-2

HEARD at Calgary, Alberta on 11, 12, 13, 16, 17, 18, 19 and 20 October 1978
Vancouver, British Columbia on 25 October 1978
Halifax, Nova Scotia on 6 November 1978
Quebec City, Quebec on 8 November 1978
Ottawa, Ontario on 14, 15, 16, 17, 20, 21, 22, 23, 24, 27, 28, 29, 30 November, 1 and 4 December 1978

BEFORE:

J.G. Stabback	Chairman
J. Farmer	Member
J.R. Jenkins	Member

APPEARANCES:

Calgary	H.J. Webber F.J. Mink	Alberta Energy Resources Conservation Board
	D. Bogdasavitch	Saskatchewan Department of Mineral Resources
	D.B. Macnamara	Canadian Petroleum Association
	A. MacLeod	Alberta Energy Company Ltd.
	F.R. Foran	The Alberta Gas Ethylene Company Ltd.
	J. Hopwood, Q.C. F.R. Foran	Alberta Gas Trunk Line Company Limited/Q & M Pipe Lines Ltd.
	S.A. Thomson	Panarctic Oils Ltd.
	H.L. Hooker	Amoco Canada Petroleum Company Ltd.
	D. Blackman	B.P. Exploration Canada Limited
	W.F. Clark	Bow Valley Exploration
	G. Dohy	Canada Cities Services Ltd.
	G.F. Hulme	Canadian Hunter Exploration Ltd.
	J.P. Peacock	Canadian Superior Oil Ltd.

R.A. Pashelka	Chevron Standard Limited
M. Orr	Chieftain Development Co. Ltd.
B.F. Willson	Committee for an Independent Canada
G.D. Nichols	Consolidated Natural Gas Limited
J.H. Farrell P.E. Brace	The Consumers' Gas Company/ Niagara Gas Transmission Limited
R.C. Muir	Dome Petroleum Limited
H. Fergusson	Dow Chemical of Canada, Limited
R.J. Gibbs, Q.C.	Foothills Pipe Lines (Yukon) Ltd.
N.J. Kathuria A. Kainz	Great Lakes Gas Transmission Company
A.P. Scott	Gulf Oil Canada Limited
T.S. Hoar	Home Oil Company Limited
R.M. Perrin	Hudson's Bay Oil & Gas Company Limited
D. Estrin A. Golden	Inuit Tapirisat of Canada
F. Saville K. Yates	Independent Petroleum Association of Canada
R.K. Dickson	Merland Explorations Limited
N. Dell	Mesa Petroleum (N.A.) Co.
D.W. MacFarland	Mobil Oil Canada Ltd.
J.J. Marshall	Norcen Energy Resources Limited
P. Scully R. Rhodes	Northern and Central Gas Corporation Limited
D.W. Rowbotham	Pacific Petroleums Ltd.
J. Stein, Q.C. G. Burden	Pan-Alberta Gas Ltd.
B.J. Waters	Paloma Petroleum Ltd.
J.R. Smith, Q.C. F.G. Homer	Alberta & Southern Gas Co. Ltd.

	D.G. Hart	PanCanadian Petroleum Limited
	J. Wansleeben	Petrofina Canada Ltd.
	J.J. Kinahan G. Aimes	Petrosar Limited
	J.W.S. McOuat I.B. MacOdrum	Polar Gas Limited
	R.A.F. Montgomery	ProGas Limited
	T.F. Liebsch	Quintana Exploration Co.
	K.D. Wellman	Saskatchewan Power Corporation
	J.M. Killey	Shell Canada Resources Limited
	J. Tessari	Shelter Oil & Gas Ltd.
	J. Holland	Star Oil & Gas Ltd.
	E.W.H. Mallabone S. Trachimovsky M.A. Brown	TransCanada PipeLines Limited
	L.D. Rae	Union Oil Company of Canada Limited
	J.A. Mercier E. Tetreau	Universal Gas Co. Ltd.
	J.F. Redgewell N. Shende	Attorney General for Manitoba
	R.P. Smith	Ontario Minister of Energy
	Me D. Houde	Procureur général du Québec
	K.J. MacDonald	National Energy Board
Vancouver	R. Edwards	Attorney General for British Columbia
	D. Duff	British Columbia Hydro and Power Authority
	R.B. Wallace	Council of Forest Industries of British Columbia
	D.G.S. Rae	Inland Natural Gas Co. Ltd.
	Ms. Mandell	Union of B.C. Indian Chiefs
	C.D. Williams, Q.C. P. Steele	Westcoast Transmission Company Limited

	G.M. Burden	Pan-Alberta Gas Ltd.
	J.W.S. McOuat	Polar Gas Limited
	C.F. Hulme	Canadian Hunter Exploration Ltd.
	J. Hopwood	Alberta Gas Trunk Line Company Limited/Q & M Pipe Lines Ltd.
	R.C. Muir	Dome Petroleum Limited
	D.W. MacFarland	Mobil Oil Canada Ltd.
	M.A. Brown E.W.H. Mallabone	TransCanada PipeLines Limited
	R. Rhodes	Northern and Central Gas Corporation Limited
	G. Dohy	Canada Cities Services Ltd.
	K.J. MacDonald	National Energy Board
Halifax	G. Evans	Nova Scotia Energy Council
	I. Gray	Government of Newfoundland and Labrador
	J. Hopwood, Q.C.	Alberta Gas Trunk Line Company Limited/Q & M Pipe Lines Ltd.
	M.A. Brown	TransCanada PipeLines Limited
	A. Potter	Independent Petroleum Association of Canada
	K. MacDonald	National Energy Board
Québec	Me D. Houde	Procureur général du Québec
	J.M. Fortier	Gaz Métropolitain, inc.
	J. Hopwood, Q.C.	Q & M Pipe Lines Ltd.
	M.A. Brown	TransCanada PipeLines Limited
	D.G. Hart	PanCanadian Petroleum Limited
	D.B. Macnamara	Canadian Petroleum Association
	F. Saville	Independent Petroleum Association of Canada
	J.J. Marshall	Norcen Energy Resources Limited
	R.D. Smith	Ontario Ministry of Energy

	P.F. Scully	Northern and Central Gas Corporation Limited
	J.H. Farrell	The Consumers' Gas Company
	A. Bigue K. MacDonald	National Energy Board
Ottawa	N. Shende	Attorney General for Manitoba
	B.A. Crane, Q.C.	Canadian-Montana Pipe Line Company
	F. Bregha	Energy Probe and Workgroup on Canadian Energy Policy
	J.H. Farrell	The Consumers' Gas Company/Niaraga Gas Transmission Limited
	J. Curran	Quasar Petroleum Ltd.
	D. Scott	Industrial Gas Users Association
	A.G. Lapalme	Union Carbide Canada Limited
	J. Hopwood, Q.C. F.R. Foran	Alberta Gas Trunk Line Company Limited
	J. Stein, Q.C. G. Burden	Pan-Alberta Gas Ltd.
	G.F. Hulme	Canadian Hunter Exploration Ltd.
	I. McDougall F. Bregha	Canadian Wildlife Federation
	B. Willson I. McDougall	Committee for an Independent Canada
	D. Gamble	Canadian Arctic Resources Committee
	R.C. Muir	Dome Petroleum Limited
	H.A. Ferguson	Dow Chemical of Canada, Limited
	F. Saville C. Kemm Yates	Independent Petroleum Association of Canada
	F. Newboldt	Sun Oil Company of Canada Limited
	N. Kathuria	Great Lakes Gas Transmission Company
	A.P. Scott G. Connell	Gulf Oil Canada Limited
	R.C. Walker	Imperial Oil Limited

F.H. Lamar, Q.C. K.J. MacDonald S. Fraser	National Energy Board
J. Carstairs	Inter-City Gas Limited
A. Golden D. Estrin D. Starkman	Inuit Tapirisat of Canada
R.P. Smith	Ontario Minister of Energy
P.F. Scully	Greater Winnipeg Gas Company
P.F. Scully	Northern and Central Gas Corporation Limited
J.J. Marshall	Norcen Energy Resources Limited
A.R. O'Brien	Midwestern Gas Transmission Company
R.C. Muir	Dome Petroleum Limited
S. Thomson	Panarctic Oils Ltd.
J. Kinahan	Petrosar Limited
J. McOuat, Q.C. I.B. MacOdrum	Polar Gas Limited
M. Brown S. Trachimovsky	TransCanada PipeLines Limited
J.D. Airth	Ultramar Canada Limited
A. Mudryj	Union Gas Limited
J. Hopwood, Q.C.	Q and M Pipe Lines Ltd.
S. Nousiainen	Canadian Labour Congress
D.B. Macnamara	Canadian Petroleum Association
J.P. Peacock	Canadian Superior Oil Ltd.
J.R. Smith, Q.C.	Alberta & Southern Gas Co. Ltd.
F.R. Foran	The Alberta Gas Ethylene Company Ltd.
D.G. Hart	PanCanadian Petroleum Limited
C. Caccia, M.P.	Member of Parliament for Davenport
F.H. Lamar, Q.C. K.J. MacDonald S. Fraser	National Energy Board

Abbreviations of Names

Alberta Energy Resources Conservation Board	"AERCB"
Saskatchewan Department of Mineral Resources	"Saskatchewan"
Attorney General for Manitoba	"Manitoba"
Attorney General for British Columbia	"British Columbia"
Ontario Minister of Energy	"Ontario"
Procureur général du Québec	"Quebec"
Government of Newfoundland and Labrador	"Newfoundland"
Government of New Brunswick	"New Brunswick"
Nova Scotia Energy Council	"Nova Scotia"
Alberta Energy Company Ltd.	"AEC"
Alberta Gas Ethylene Company Ltd.	"AGEC"
Alberta Gas Trunk Line Company Limited	"AGTL"
Alberta and Southern Gas Co. Ltd.	"Alberta and Southern" or "A & S"
Amoco Canada Petroleum Company Ltd.	"Amoco"
Bow Valley Exploration	"Bow Valley"
British Columbia Hydro and Power Authority	"B.C. Hydro"
British Columbia Petroleum Corporation	"BCPC"
B.P. Exploration Canada Limited	"B.P. Canada"
Canada Cities Services Ltd.	"Cities"
Canadian Arctic Resources Committee	"CARC"
Canadian Hunter Exploration Ltd.	"Canadian Hunter"
Canadian Labour Congress	"CLC"
Canadian-Montana Pipe Line Company	"Canadian-Montana"

Canadian Petroleum Association	"CPA"
Canadian Superior Oil Ltd.	"Canadian Superior"
Canadian Wildlife Federation	"CWF"
Chevron Standard Limited	"Chevron"
Chieftain Development Co. Ltd.	"Chieftain"
Committee for an Independent Canada	"CIC"
Consolidated Natural Gas Limited	"Consolidated"
Council of Forest Industries of British Columbia	"COFI"
Dome Petroleum Limited	"Dome"
Dow Chemical of Canada, Limited	"Dow"
Energy, Mines and Resources	"EMR"
Energy Probe and Workgroup on Canadian Energy Policy	"Energy Probe"
Foothills Pipe Lines (Yukon) Ltd.	"Foothills"
Gaz Métropolitain, inc.	"Gaz Métropolitain"
Geological Survey of Canada	"GSC"
Great Lakes Gas Transmission Company	"Great Lakes"
Greater Winnipeg Gas Company	"Greater Winnipeg"
Gulf Oil Canada Limited	"Gulf"
Home Oil Company Limited	"Home"
Hudson's Bay Oil and Gas Company Limited	"HBOG"
Imperial Oil Limited	"Imperial"
Independent Petroleum Association of Canada	"IPAC"
Industrial Gas Users Association	"IGUA"
Inland Natural Gas Co. Ltd.	"Inland"
Inter-City Gas Limited	"Inter-City"

Inuit Tapirisat of Canada	"Inuit Tapirisat"
Merland Explorations Limited	"Merland"
Mesa Petroleum (N.A.) Co.	"Mesa"
Midwestern Gas Transmission Company	"Midwestern"
Mobil Oil Canada Ltd.	"Mobil"
Niagara Gas Transmission Limited	"Niagara"
Norcen Energy Resources Limited	"Norcen"
Northern and Central Gas Corporation Limited	"NCGas"
Pacific Petroleums Ltd.	"Pacific"
Paloma Petroleum Ltd.	"Paloma"
Pan-Alberta Gas Ltd.	"Pan-Alberta"
Panarctic Oils Ltd.	"Panarctic"
PanCanadian Petroleum Limited	"PanCanadian"
Petrofina Canada Ltd.	"Petrofina"
Petrosar Limited	"Petrosar"
Polar Gas Limited	"Polar Gas"
Procor Limited	"Procor"
ProGas Limited	"ProGas"
Q & M Pipe Lines Ltd.	"Q & M"
Quasar Petroleum Ltd.	"Quasar"
Quintana Exploration Co.	"Quintana"
Saskatchewan Power Corporation	"SPC"
Shell Canada Resources Limited	"Shell"
Shelter Oil & Gas Ltd.	"Shelter"
Star Oil & Gas Ltd.	"Star"
Sun Oil Company of Canada Limited	"Sun"
Texaco Canada Inc	"Texaco"

The Consumers' Gas Company	"Consumers'"
TransCanada PipeLines Limited	"TransCanada" or "TCPL"
Ultramar Canada Limited	"Ultramar"
Union Carbide Canada Limited	"Union Carbide"
Union Gas Limited	"Union Gas"
Union Oil Company of Canada Ltd.	"Union Oil"
Union of B.C. Indian Chiefs	"UBCIC"
Universal Gas Co. Ltd.	"Universal"
Westcoast Transmission Company Limited	"Westcoast"

Abbreviations Of Terms

Bcf —Billion cubic feet

Bcf/d —Billions of cubic feet per day

Btu —British thermal unit

cf —cubic foot

CPI —consumer price Index

GNP —Gross National Product

LNG —Liquefied Natural Gas

Mb/d —Thousands of barrels per day

MMcf —Million cubic feet

MMcf/d —Million cubic feet per day

NGL —Natural Gas Liquid

RDP —Real Domestic Product

SNG —Synthetic Natural Gas

Tcf —Trillion cubic feet

Reference Reports

"1975 Gas Report"	Canadian Natural Gas Supply and Requirements – National Energy Board – April 1975
"1978 Oil Report"	Canadian Oil Supply and Requirements – National Energy Board – September 1978
"1977 Oil Report"	Canadian Oil Supply and Requirements – National Energy Board – February 1977
"Northern Pipelines Report"	National Energy Board Reasons for Decision Northern Pipelines – June 1977
"Dome/Cochin Report" January 1974	Report to the Governor in Council in the Matter of Applications under the National Energy Board Act of Dome Petroleum Limited and Cochin Pipe Lines Ltd. – January 1974
"August 1970 Report to the Governor in Council"	National Energy Board Report to the Governor in Council In the Matter of the Applications under the National Energy Board Act of Alberta & Southern Gas Co. Ltd., Alberta Natural Gas Company, Canadian-Montana Pipe Line Company, Consolidated Natural Gas Limited, Consolidated Pipe Lines Company, TransCanada PipeLines Limited, Westcoast
"EMR Report EP 77-1"	Department of Energy, Mines and Resources
"AERCB Report 78-18"	Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur at 31 December 1977
"AERCB Report 78-E"	The Supply of and Demand for Alberta Gas – May 1978 (the AERCB submission to the inquiry)
"AERCB Report 74-D"	In the Matter of an Application of Pan-Alberta Gas Ltd under the Gas Resources Preservation Act, February 1974.

Reference Studies

Canadian Gas and North American Energy Balances: Market Prospects and Public Policies – October 1978 – W.J. Levy (prepared for IPAC)

The Benefits and Costs Associated with Exports of Natural Gas from Western Canada – August 1978 – Canadian Resourcecon Ltd. (prepared for IPAC)

Ontario Energy Demand Analysis and Gas Penetration Forecast – August 1978 – Hycarb Engineering Ltd. (prepared for NCGas)

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Forecasts of Industrial Natural Gas Demand in Ontario and Quebec 1976 – 2000 – June 1978 – Canadian Resourcecon Ltd. (prepared for Dome)

Natural Gas in Canada – 1978 – August 1978 – Manecon Associates Limited (prepared for Alberta & Southern and Canadian-Montana)

Replacement of Imported Crude Oil by Natural Gas in the Canadian Fuel Market – November 1978 – Fluor Canada Ltd. (prepared for Panarctic)

Western Canada Foothills Gas Potential – August 1978 – Kloepfer & Associates Ltd. (prepared for IPAC)

Ultimate Gas Potential of Western Canada – August 1978 – Kloepfer & Associates Ltd. (prepared for Dome)

Definitions

Associated Gas*	Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir, except where the volume of oil is small and where production of such gas does not significantly affect the crude oil recovery.
Beyond Economic Reach Reserves	Those established reserves which because of size, geographic location or composition are not considered economically connectable to a pipeline at the present time.
Blowdown	The production of gas either from the gas cap of an oil reservoir normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.
Conventional	With reference to natural gas reservoirs or production from them – those reservoirs from which natural gas will flow in commercial quantities without application of any technology other than that usually associated with gas well completions; the production from such reservoirs.
Conventional Areas	Those areas of Canada which have a lengthy history of hydrocarbon production.
Conventional Producing Areas	Same as Conventional Areas.
Daily Contract Quantity	The average daily rate of take specified in a contract negotiated between a gas supplier and a gas purchaser.
Deep Basin	In general terms, the western part of the Western Canada Sedimentary Basin characterized by rapid thickening of the Mesozoic sedimentary section westward. Canadian Hunter uses the term more specifically to describe an area immediately east of the foothills belt, extending for some 400 miles from approximately 52°30′ north latitude in Alberta, to 57° in British Columbia. The Mesozoic section in this area is generally of low permeability and is considered by Canadian Hunter to be almost universally gas-saturated.
Deferred Reserves	Those volumes of established reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project, are not now available for market.
Deliverability	A general term used to refer to an actual or expected rate of natural gas production.

Dempster Lateral	A proposed pipeline to transport gas from the Mackenzie Delta area along a route generally parallel to the Dempster highway, to connect with the Alaska Highway Pipeline near Whitehorse in the Yukon Territory.
Elmworth or Elmworth/Wapiti Area	An area of the Deep Basin of Alberta, centred some 20 miles southwest of Grande Prairie, currently undergoing active development of natural gas reserves.
Established Reserves*	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
Initial Established Reserves*	Established reserves prior to the deduction of any production.
Remaining Established Reserves*	Initial established reserves less cumulative production.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Frontier Areas	Those areas of Canada which have a potential for but no history of production. These include the Mackenzie Delta-Beaufort Sea area, the Arctic Islands and the offshore areas.
Frontier Reserves	Reserves located in the frontier areas.
Heavy Fuel Oil	In this report the term heavy fuel oil is used to include bunker fuel oils which are No. 5 and No. 6 fuel oils and also industrial fuel oil which is No. 4 fuel oil.
Hog Fuel	Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects that result from the operation of pulp mills, sawmills and plywood mills.
Initial Volume in-place*	The gross volume of raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
Infill drilling	The process of drilling additional wells in a producing field, thereby reducing the spacing between wells.
International Price of Crude Oil	A generalization for the "going price" of crude oil in the world markets.

Light Fuel Oil — In this report the term light fuel oil is used to include furnace fuel oil which is No. 2 fuel oil and stove oil which is No. 1 fuel oil. The major volume of light fuel oil used in Canada is furnace fuel oil.

Marketable Natural Gas* — Natural gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel. Marketable natural gas excludes field and plant fuel and losses, excepting those related to downstream reprocessing plants.

Massive Hydraulic Fracturing — A technology applied to low permeability reservoirs which creates fractures in the pay section to improve reservoir productivity. The fractures are induced through injection of fluid under pressure, and held open after the pressure is released by a propping agent introduced with the injected fluid. It differs from fracturing techniques in common use in conventional reservoirs in that much larger volumes of injected fluid and propping agent are used, so that fractures of greater magnitude result.

Natural Gas Liquids* — Natural gas liquids are those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus or a combination thereof.

Non-Associated Gas* — Natural gas not in contact with crude oil in the reservoir or natural gas in contact with crude oil where the volume of oil is small and where production of such gas does not significantly affect the crude oil recovery.

Permeability — Permeability is a property of a porous medium and is a measure of the capacity of the medium to transmit fluids.

Quad — A unit of energy equivalent to 10^{15} British thermal units.

Rate of Take — The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which that production is obtained. For example 1:7300 means one million standard cubic feet per day of production for each block of 7300 million standard cubic feet of initial established reserves.

Raw Natural Gas* — The lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids.

Remaining Established Reserves — See "Established Reserves"

Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.
Reserves Appreciation	Incremental change in established reserves resulting from extensions and revisions to existing pools.
Self-Reliance	Canadian self-reliance in energy can be measured by the degree to which Canada is able to depend on its own resources to meet its own energy requirements. Concerns with the security of supply have led to the establishment of a goal limiting net imports or crude oil to either one-third of Canada's feedstock requirements or 800 Mb/d, whichever is less, by 1985.
Solution Gas*	Natural gas which is in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.
Straddle Plant	A natural gas processing plant in which gas is further processed, subsequent to field processing, to remove liquid components. Generally, the plant is located on a main transmission system and is said to ''straddle'' the pipeline; also known as a reprocessing plant.
Supply Capability	The deliverability that could be achieved from a gas reservoir or group of reservoirs when restricted only by reservoir performance, well density and well capacity, field processing capacity and contract rates.
Supply Tracking	A supply forecasting procedure utilized during a period when supply capability exceeds demand, whereby deliverability is restricted to (or''tracks'') that demand until such time as supply capability falls below the demand level.
Ultimate Potential*	An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.
World Price	See ''International Price''

*The Board has adopted the reserves terminology and definitions recommended by the Joint Task Force on Uniform Reserves Terminology, 1978. Definitions marked * are Task Force definitions of terms used in this report.

Metric Conversion Table

1 cubic foot of natural gas (14.73 psia and 60°F)	=	0.028 327 84 cubic metres (101.325 kilopascals and 15 degrees Celsius)
1 $Btu_{60/61}$	=	1 054.615 joules
1 quad	=	1.054 615 x 10^9 gigajoules
1 $Btu_{60/61}$ per cubic foot (Saturated, 14.73 psia and 60°F)	=	0.037 887 67 megajoules per cubic metre (zero moisture, 101.325 kPa and 15°C)
1 inch	=	0.0254 metres
1 foot	=	0.3048 metres
1 psi	=	6.894 757 kilopascals
1 pound (avdp)	=	0.453 592 4 kilograms
1 short ton	=	907.184 7 kilograms
1 barrel	=	0.158 987 3 cubic metres

Chapter 1
Summary and Conclusions

Early in 1978 the National Energy Board felt it advisable, because of changing circumstances in the natural gas industry, to make an appraisal of the supply of gas in relation to reasonably foreseeable requirements for use in Canada and for authorized exports.

The Board also felt it timely and appropriate, in the light of possible applications for licences to export natural gas, to re-examine its procedures for determining the surplus of natural gas.

The Board wished to receive advice from the energy sector, the provinces and the general public on matters of gas supply, demand and surplus. By its Hearing Order GHR-1-78 dated 26 April 1978 (Appendix 1), the Board announced a public inquiry would be held commencing 11 October 1978 in Calgary, Alberta, followed by sittings in Vancouver, British Columbia, Halifax, Nova Scotia, Quebec City, Quebec, and Ottawa, Ontario.

In response to the Board's Order, 89 written submissions were received. All provinces, except Prince Edward Island, were represented, as were the two major petroleum industry associations, CPA and IPAC. The inquiry occupied 26 days and resulted in some 6000 pages of transcript.

The purpose of this inquiry was to examine Canadian gas supply and demand and to review procedures for calculating surplus. In its 1975 Gas Report* the Board had set forth certain general principles respecting surplus calculation procedures. The Board now invited submissions on specific surplus calculation procedures which would embody as many as possible of the aspects of the principles set forth in that Report.

It was not the purpose of the inquiry to consider and determine any specific applications which were before the Board or which might come before the Board in the near future. Nor was it intended that there would be any decision arising out of the inquiry which would authorize exports of natural gas or the construction of any new pipeline facilities. However, it was the intent to determine the extent to which reserves and deliverability of gas exceeded the reasonably foreseeable requirements for gas in Canada and currently authorized exports. Such surplus determination would form the basis for considering specific export applications in subsequent proceedings.

This report deals with the written and oral submissions made to the Board during that inquiry and with the findings of the Board on the evidence so rendered. The report deals first with supply, covering reserves and deliverability from conventional areas and then similar information on frontier areas.

Requirements are discussed first for markets currently receiving natural gas service ("existing markets") and then for markets beyond the reach of existing gas transmission and distribution facilities ("expansion markets").

A chapter on supply/demand balance is followed by one on surplus procedures and calculations. Other related issues are dealt with in the final chapter of the Board's Report. Appendices, where applicable, have been reported in both Imperial and metric units.

The main conclusions of this Report are:

- The Board's estimate of remaining established reserves in conventional areas is 66.1 Tcf at the end of 1978. This is 4.7 Tcf more than estimated for year-end 1976 in the Northern Pipelines Report. In the Mackenzie Delta-Beaufort Sea area, the Board finds no change to be required in the estimate of established marketable gas presented in the Northern Pipelines Report, i.e. 5.3 Tcf. The estimate of established reserves of marketable gas in the Arctic Islands has been increased from 7.3 Tcf to 9.2 Tcf. The Board does not believe a meaningful estimate of established reserves in the East Coast offshore areas is possible at this time.

- Growth in demand for natural gas in existing markets will average 3.0 percent per year between 1978 and 2000. For the year 1990 the forecast is some 11 percent lower than the forecast shown in the Northern Pipelines Report. This reduction results from a lower forecast of economic activity and a lower demand for natural gas for the generation of electricity than in that Report.

- The Board has made an estimate of potential sales of

*Full titles of reports and studies referred to in this report are listed in the abbreviations section at the front of the report.

natural gas in expansion markets in Quebec and the Maritimes which might take place given specific pricing and other assumptions. The Board has made allowance for this demand as part of Canadian requirements, recognizing that the justification for such expansion will be required to be demonstrated in a subsequent hearing. The Board estimates that under certain conditions, additional net sales of natural gas east of Ontario might be approximately 180 Bcf in 1990, rising to some 255 Bcf in the year 2000. The amounts of imported oil which might be displaced by additional sales of natural gas in Quebec and the Atlantic Provinces are some 80 Mb/d in 1990 increasing to some 110 Mb/d in the year 2000.

- The Board has concluded that the determination of a surplus of natural gas should be made using three tests; a Current Deliverability Test, a Current Reserves Test and a Future Deliverability Test. All three tests would have to be met before the Board would deem a surplus to exist. Any new exports which might be authorized on the basis of deliverability from established reserves only would have the same status as currently authorized exports in regard to interruptibility. However, any new exports that are dependent upon deliverability from established reserves plus reserves additions would be subject to interruption. Subsequently, if reserves additions should be lower than had been forecast or should Canadian requirements be higher than expected, these conditional exports would be reduced or rescinded to the extent that the required deliverability in any year during the extended period was not sufficient to meet expected demand plus firm authorized exports.

- The Board finds that surplus gas exists and that the approximate size of the surplus is 2 Tcf. The precise amount which could be exported will depend upon the annual quantities and term of any licences granted. The determination of any such surplus will be based on the methodology set forth in this report.

- The Board has decided that ethane should not be considered as part of the surplus determination of natural gas and should be treated as a separate product as are ethylene, propane and butanes.

A summary of the report, by chapter, follows.

NATURAL GAS SUPPLY

Conventional Areas

Remaining established reserves of marketable natural gas in the conventional producing areas of Canada are estimated by the Board to be 66.1 Tcf as of 31 December 1978. This is 4.7 Tcf more than the estimate of 61.4 Tcf (as of 31 December 1976) published in the Northern Pipelines Report.

The Board has made estimates of additions to reserves and ultimate potential for three cases – an expected case and high and low cases. For its expected case the Board forecasts that reserves additions during the period 1978 to 2000 will total 38 Tcf. Its corresponding estimate of ultimate potential is 147 Tcf. The expected quantities are higher than those forecast in the Northern Pipelines Report, reflecting a somewhat more favourable supply outlook currently.

The Board has devoted considerable attention to the prospects of the Deep Basin of Alberta and British Columbia. The established reserves of the Elmworth/Wapiti area, an area under active development within the Deep Basin, are estimated to be in the order of 1 Tcf, all in conventional reservoirs. No gas in the low permeability sands of the Deep Basin has been placed in the established category at this time. Further advances in technology which might lead to economic recovery of a portion of this resource would permit its inclusion in the future.

The Board has made a projection of deliverability based on production capability assuming no market constraints. This capability, 3.5 Tcf/year in 1979, peaks in 1981 at 3.8 Tcf/year, and then declines, reaching 1.9 Tcf/year by the year 2000, the end of the forecast period. A comparison of the Board's deliverability forecast with that published in the Northern Pipelines Report follows:

Supply Capability From Conventional Areas
NEB Forecasts

(Bcf/year at 1000 Btu/cf)

	1979	1985	1990	1995	2000
Current Forecast	3533	3455	2981	2341	1937
Northern Pipelines Report	3236	3322	2776	2003	N/A
Increase	297	133	205	338	N/A

Frontier Areas

Remaining established reserves of marketable natural gas in the frontier areas are estimated by the Board to be 14.5 Tcf as of 31 December 1978, of which 5.3 Tcf are in the Mackenzie Delta area and 9.2 Tcf are in the Arctic Is-

lands. The Mackenzie Delta area estimate is unchanged from that published in the Northern Pipelines Report but that for the Arctic Islands is higher by 1.9 Tcf. The Board made no forecast of reserves for the other frontier areas. It also made no forecast of reserves additions for the frontier areas because of the high degree of speculation involved, but cites submittors' estimates as representative of a range of volumes that might be attainable. With respect to ultimate potentials of the frontier areas, the Board has adopted the estimates of the Geological Survey of Canada published in EMR Report 77-1.

The Board continues to rely on its estimate of deliverability of some 700 MMcf/d from the Mackenzie Delta area published in the Northern Pipelines Report. For purposes of illustration only, the effect on total Canadian supply of Mackenzie Delta production, beginning in 1987, is demonstrated in Figure 4-1.

NATURAL GAS REQUIREMENTS

Demand for Total Energy

The Board prepares its estimates of demand for natural gas within the framework of the demand for total energy and for various energy forms. This total energy demand forecast methodology was described in some detail in the Board's 1978 Oil Report. Total energy demand in the various sectors and regions is linked to population, energy prices and selected economic indicators. The fuel selection process is analysed separately by estimating future market shares.

The underlying forecast of the economic and demographic variables is based on the Board's version of the Candide 1.2 econometric model of the Canadian economy.

The forecast is the same as that published in the 1978 Oil Report. To assess possible high and low demand cases the Board assumes that world oil prices will respectively decline or increase in real terms at a rate of approximately 5 percent per annum. Also two macroeconomic forecasts are considered.

In this present report the Board assumes for its base case forecast that the world price of crude oil will remain constant in real terms at its 1977 level and that the price of domestic crude oil will approach the world level by the end of 1981. The forecast for existing market areas also assumes that the Toronto city-gate price of natural gas will maintain its present relationship of approximately 85 percent of the domestic crude oil price on a thermal equivalence basis.

The Board expects total primary energy demand in Canada to increase from 8.9 quads in 1978 to 12.6 quads by 1990 and to 17.1 quads by the year 2000.

The growth in primary energy demand is expected to slacken during the first half of the forecast period as a result of increasing energy real prices until 1981, lower economic and population growth and the effects of various energy conservation measures. During the second half of the forecast period, growth in primary energy demand is expected to increase, partly as a result of the fact that higher real energy prices and other conservation measures are assumed to have had most of their impact by about 1990. For 1990 the high and low cases indicate that total primary energy demand could be 21 percent higher or 13 percent lower than the base case forecast.

Demand for Natural Gas—Existing Markets

The Board expects that growth in natural gas net sales will be approximately 3.0 percent per annum during the forecast period, increasing from 1506 Bcf in 1978 to 2134 Bcf by 1990 and to 2893 Bcf in the year 2000. Net sales in 1990 could be 19 percent higher or 14 percent lower than the Board's base case, without market expansion, depending on the assumptions made regarding the major determinants of energy demand.

The current forecast of lower growth in natural gas demand is the result of lower economic growth, increasing energy prices and other conservation measures.

Demand in the residential sector in existing market areas is expected to increase from 338 Bcf in 1978 to 440 Bcf in 1990 and to 545 Bcf in 2000 with an average increase over the whole forecast period of 2.2 percent per annum. Natural gas requirements in the commercial sector are forecast to increase at an average annual rate of 2.9 percent during the forecast period, from 336 Bcf in 1978 to 499 Bcf in 1990 and to 632 Bcf in year 2000. The demand by the industrial sector is expected to increase at the fastest rate averaging 4.0 percent per annum for the forecast period, increasing from 548 Bcf in 1978 to 815 Bcf in 1990 and to 1308 Bcf in year 2000.

The present forecast of net sales for the year 1990 is approximately 11 percent lower than the forecast that was shown in the Northern Pipelines Report. This lower forecast is generally in line with the evidence presented at this inquiry. It is also the result of a lower forecast of economic activity and a lower demand for natural gas for the generation of electricity than those forecast for the Northern Pipelines Report.

Introduction of Gas into Eastern Markets

Natural gas industry submittors to the inquiry generally favoured expansion of natural gas markets eastward of the existing pipeline system in order to augment producer cash flow, to reduce eastern Canada's dependence on foreign sources of crude oil and to improve Canada's international balance of payments, provided that such expansion were justifiable in economic terms. Some submittors who supported expansion recommended that greater emphasis be placed upon non-economic issues in assessing the national interest of such a proposal. Opponents to expansion cited issues such as excess refinery capacity in eastern Canada and the problem of disposing of surplus heavy fuel oil.

Ontario and Manitoba along with the major eastern gas distributors expressed concern that existing customers might be expected to subsidize expansion through higher tariffs.

The Board's treatment of expansion markets takes into account statements by the Minister of Finance and by the Minister of Energy, Mines and Resources in August 1978, which can be summarized as follows: high field prices for natural gas have encouraged more extensive exploration programs which have begun to increase natural gas supply. While Canada now has increased supplies which provide an opportunity to reduce its increasing dependence on imported oil, the fixed price relationship of natural gas to crude oil has not allowed gas the flexibility in price needed to penetrate new markets in Canada. Discussions with Alberta will seek to provide the price flexibility needed for market expansion.

In this regard, the Board is aware of the formation of a Federal-Alberta Task Force to establish mechanisms for implementation of the agreed policy objective of encouraging natural gas expansion in eastern Canada. This would be achieved by means of an incentive pricing scheme whereby incremental volumes of Alberta gas would be made available to new markets east of Alberta for less than the present selling value for a fixed duration. Such mechanisms would include appropriate actions by federal and provincial governments and industry to achieve the desired objective of increased self-reliance.

The Board has made an estimate of the potential sales that could be made if specific competitive conditions existed and if surplus heavy fuel oil were disposed of. The Board has provided for this demand as a part of Canadian requirements recognizing, however, that there is a need for a demonstration in a subsequent hearing that such potential market exists.

Displacement of Petroleum Products

Submittors recommended that problems arising from the displacement of petroleum products by natural gas in eastern Canada be solved by the exportation of heavy fuel oil to the United States and/or by modification of current refining practices, notably through the construction of facilities for the upgrading of heavy fuel oil.

In prevailing circumstances, the Board considers that there are but limited opportunities for the profitable exportation of increased volumes of heavy fuel oil. With the base case for gas expansion, the Board remains of the view that refineries in eastern Canada could adapt to the different product mix involved. The Board believes that the investment required would be most appropriately undertaken by individual refineries rather than at a central facility. Even if this were achieved, a surplus of crude distillation capacity will likely remain and efforts should be made in conjunction with United States authorities for its mutually beneficial utilization.

Demand for Natural Gas—New Markets

The Board has developed estimates of the demand for natural gas in these new market areas of eastern Canada. Specifically, gas demand estimates have been prepared for areas in Quebec not presently served by gas and for New Brunswick and Nova Scotia. As well, a gas expansion scenario has been developed for the existing gas franchise area of Quebec. The Board has developed these estimates in order to assure itself that adequate provision has been made for potential new domestic markets for natural gas before additional exports are considered. Although the Board did not prepare gas expansion scenarios for areas west of Quebec, it is not precluding the possibility of some expansion occurring, say, in Ontario or Manitoba. The Board has not made any provision in its forecast for extension of natural gas service to Vancouver Island.

In developing its estimates, the Board assumed that natural gas would have a price advantage over competing fuels at the burner tip in eastern Canadian markets. It also assumed that the present availability of heavy fuel oil would not inhibit gas penetration. The conditions under which these assumptions might materialize have not been the central focus of the Board's investigations in this area. Furthermore, in making these assumptions, the Board is not implying that they will in fact materialize. The assumptions simply reflect conditions felt necessary to ensure a significant degree of gas penetration into eastern Canada. In summary, it is estimated that under certain conditions additional net sales of natural gas east of Ontario

might be approximately 180 Bcf in 1990, rising to some 255 Bcf in 2000. Although the Board's estimates are reasonably close to those of many submittors, it is not surprising that there are some significant differences, given the major uncertainties and difficulties associated with developing such estimates.

SUPPLY/DEMAND BALANCE

The Board compared its forecast of gas supply from the conventional areas with its forecast of Canadian demand, including eastern market expansion, plus remaining authorized export volumes. The supply/demand balance was constructed in a similar way to that presented in the Northern Pipelines Report.

Alberta requirements are fully met over the forecast period. Overall surplus supplies were allowed to flow to markets in British Columbia or east of Alberta when these markets were deficient. Total demand east of Alberta, including authorized exports, can be met until 1992, assuming no additional restriction resulting from the Alberta protection procedure. Total demand in British Columbia can be met until a small deficiency occurs in 1999.

In aggregate, the total Canadian demand plus authorized exports can therefore be met until 1992. This represents an overall improvement in the Board's assessment of the total Canadian supply/demand balance since its Northern Pipelines Report. In that report, the Board concluded that deficiencies would occur beginning in 1983.

SURPLUS

The Board has concluded that the procedure for the determination of the surplus of natural gas remaining after making due allowance for Canadian requirements and authorized exports should consist of three tests. These tests are a Current Deliverability Test, a Current Reserves Test and a Future Deliverability Test. All three tests would have to be met before the Board would deem a surplus to exist.

Under the Current Deliverability Test annual quantities of gas could be deemed to be surplus if forecast annual deliverability from established reserves exceeded expected Canadian demand plus authorized exports for a minimum of five years. Under the Current Reserves Test natural gas may be deemed surplus to the extent that available established reserves are calculated to exceed a quantity equal to 25 times the current year's Canadian demand plus the total authorized exports. Under the Future Deliverability Test annual quantities of gas could be deemed to be surplus provided forecast deliverability from established reserves and forecast reserves additions exceeded expected Canadian demand plus authorized exports for some ten years.

For any new licence which might be granted, exports during that portion of the period of the licence which could be supplied from established reserves deliverability would be firm. For the balance, if any, of the licence period, in which exports would rely on deliverability from reserves additions, such exports could be subject to interruption.

The Board does not believe that established frontier natural gas reserves, forecast additions to these reserves, or deliverability from these reserves can be included in the calculation of Deliverability and Reserves Tests at this time. The Board does not believe it would be appropriate to include frontier reserves until the Board has granted a certificate and is satisfied that a transmission system to connect these frontier reserves to market will be constructed.

The three-test procedure outlined above replaces the reserves test previously used by the Board. As outlined in the 1975 Gas Report, the single test procedure was inadequate in that it was possible for the reserves test to be met even during a period when difficulties were being experienced in meeting Canadian requirements due to deliverability constraints. Thus, while the Current Reserves Test under the new procedure is somewhat less stringent than the previous reserves test in that the present procedure looks at 25 times the Canadian demand in the current year plus authorized exports whereas the previous reserves test looked at 25 times estimated Canadian demand four years in the future plus authorized exports, the overall protection provided by the new procedure is greater because of the deliverability standards that are imposed.

Under the Deliverability Tests it will be necessary to examine proposed new exports in order to determine whether or not the forecast deliverability will be equal to or greater than the proposed levels of demand for the specified minimum periods of time. Hence, no definite surplus quantity for each year can be found prior to specification of a proposed deliverability pattern for the proposed new exports and the application of the Deliverability Tests to this proposed production profile.

To illustrate how the annual surplus would be determined the Board has calculated three possible cases based on the established reserves as determined by the Board as of 31 December 1978 and its forecast of future reserves additions. Case 1 shows that a licence for 200 Bcf per year

could be authorized for a four-year period with a four-year extension based on the Future Deliverability Test. Case 2 shows that it would be possible to grant a licence for 500 Bcf per year for a firm three years plus an extension for an additional one year. Case 3 shows that it would be possible to grant a licence for 400 Bcf per year for two years and 200 Bcf for a second two years for the firm period of the licence plus an extension for four years.

The Current Reserves Test indicates that as of 31 December 1978 a surplus of 3.8 Tcf exists. It should be noted that the new exports under the foregoing deliverability illustrations total 1.6 Tcf in Case 1, 2.0 Tcf in Case 2, and 2.0 Tcf in Case 3. These tests indicate that, at the present time, deliverability is the governing factor in respect of the volume of gas that can be declared surplus.

Although there are many varying patterns of export volumes which could be developed under the new surplus tests, actual volumes which might be approved will be the subject of future hearings with respect to applications for licences to export gas.

The Board has concluded that any new exports which might be authorized on the basis of deliverability from established reserves only (i.e. under the Current Deliverability Test) would have the same status as currently authorized exports in regard to interruptibility. However, any new exports that are dependent upon deliverability from established reserves plus reserves additions, (i.e. the extension portions of the possible export cases illustrated by the Board), would be subject to interruption. Subsequently, if reserves additions should be lower than had been forecast or should Canadian requirements be higher than expected, these conditional exports would be reduced or rescinded to the extent that the required deliverability in any year during the extended period was not sufficient to meet expected Canadian demand plus firm authorized exports.

OTHER ISSUES

Treatment of Ethane

The Board has accepted the arguments of some submittors that ethane should be treated as a separate product as are ethylene, propane and butanes. The Board, therefore, has deducted from its estimate of natural gas reserves the shrinkage associated with the extraction of ethane in existing and anticipated processing facilities.

In future, an applicant for a licence to export ethane will only be required to demonstrate that the proposed export volumes are surplus to the reasonably foreseeable requirements for ethane in Canada.

Chapter 2
Natural Gas Supply

CONVENTIONAL AREAS

Established Reserves

Views of Submittors

Estimates of remaining marketable gas reserves encompassing all of the conventional producing areas were received from CPA, Consolidated, Dome, Gulf, HBOG, Norcen, Polar, ProGas and TransCanada. Imperial and Home submitted estimates for western Canada only. Estimates for the respective provinces were submitted by AERCB, British Columbia, Saskatchewan, and SPC. Westcoast submitted estimates for its own supply area. Submittors' estimates are compared in Table 2-1.

The estimates of remaining marketable gas reserves submitted by the majority of submittors were based generally upon the estimates of reserves by provincial regulatory agencies, NEB, or CPA and modified in some cases to reflect the submittors' own data and interpretation. The major producing companies and many independent operators submitted reserves estimates for pools and fields which they operated or in which they had a substantial interest.

CPA acknowledged that its estimates for Alberta and British Columbia were understated since they included only nominal reserves attributed to recent discoveries.

Because of the early stage of development of those discoveries and the limited amount of available data, it was not possible for it to prepare definitive estimates.

Gulf adopted the proved reserves category of the CPA, hence its estimates would also be understated.

TransCanada submitted an estimate of remaining reserves for Alberta of 59.7 Tcf, which was 1.8 Tcf higher than the AERCB estimate of 57.9 Tcf. It was explained that the difference was the result of additional gas in certain fields in which TransCanada had gas purchase contracts and in which its gas reserves estimates differed by 1.8 Tcf from those contained in AERCB Report 78-18.

Views of the Board

The Board is appreciative of the amount of supporting reservoir data included with individual pool estimates provided by submittors.

The Board has made an estimate of remaining established reserves of marketable gas in the conventional areas based on individual pool studies using available reservoir data from drilled wells and after considering the evidence submitted at the inquiry. The Board's estimates are compared with those of the submittors as of 31 December 1977 in Table 2-1. In addition, the Board has made a preliminary estimate of remaining established reserves for 31 December 1978 of 66.1 Tcf. This estimate is based on an analysis of gross reserves additions to 31 October 1978 projected to 31 December 1978.

The Board has included in this report as Appendix 2-A its estimates of established reserves for pools in Alberta and British Columbia for which its estimates differ significantly from those published by provincial agencies. This is in response to IPAC's suggestion that this information would be helpful to industry.

In comparing the Board's total Alberta estimate with that of AERCB, it should be noted that the Board's reservoir recovery factors are commonly lower. This situation arises from a decision of the Board in 1973 to increase its estimate of established reserves by 1.7 Tcf by increasing reservoir recovery factors in certain pools to account for higher natural gas prices. This is discussed in the Board's 1974 Dome/Cochin Report. AERCB subsequently increased its provincial reserves estimates, by 3.7 Tcf, for the same reason, an action documented in its Report 74-D. However this increase was partially offset by a reduction of 1.4 Tcf in the estimated reserves of small pools made by AERCB in 1976. The overall result is that the Board assigns nominally lower reserves than AERCB to many Alberta pools.

Table 2-1

REMAINING RESERVES OF MARKETABLE GAS CONVENTIONAL PRODUCING AREAS

31/12/77

(Tcf @ 1000 Btu/cf)

	B.C.	Alta.	Sask.	Southern Territories	Western Canada Total	Ontario and Other Eastern Canada	Canada Total
AERCB	—	57.9	—	—	—	—	—
Saskatchewan[2]	—	—	0.8	—	—	—	—
British Columbia	7.4	—	—	—	—	—	—
CPA[1]	7.4	52.2	1.2	0.8	61.6	0.3	61.9
Consolidated	7.3	57.5	1.4	0.5	66.7	0.3	67.0
Dome	7.9[3]	57.9	0.8	—	66.6	0.3	66.9
Gulf[2]	6.7	46.3	0.8	0.6	54.4	0.3	54.7
Home	—	—	—	—	66.0	—	—
HBOG	6.2	57.9	1.0	0.5	65.6	0.3	65.9
Imperial	7.0	56.0	1.0	1.0	65.0	—	—
Norcen	7.4	57.9	1.0	0.5	66.8	0.3	67.1
Polar Gas	7.4	57.9	0.8	0.5	66.6	0.2	66.8
ProGas	7.4	57.9	0.8	0.5	66.6	0.2	66.8
SPC	—	—	1.0	—	—	—	—
TransCanada	7.4	59.7	0.8	0.5	68.4	0.3	68.7
Westcoast[1]	6.8	—	—	0.3	—	—	—
NEB established	6.4	56.5	1.0	0.3	64.2	0.3	64.5
NEB 31/12/78 established	6.6	57.9	1.0	0.3	65.8	0.3	66.1

[1] Tcf at 14.73 psia and 60°F
[2] Tcf at 14.65 psia and 60°F
[3] Includes southern Territories

Reserves Additions and Ultimate Potential

Views of Submittors

Forecasts of reserves additions and/or estimates of ultimate potential for all or portions of the conventional producing areas were provided by 24 submittors. Most estimates of ultimate potential were for the producing provinces of Alberta and British Columbia.

At the Board's previous inquiry on natural gas supply and requirements in 1974 and at the Northern Pipelines hearing, the submittors' forecasts of reserves additions and estimates of ultimate potential were somewhat less optimistic than at the present inquiry. This change was attributed to the increased drilling activity of the past few years which resulted in additional volumes of natural gas being discovered and known discoveries being developed. Forecasts of total reserves additions are compared in Table 2-2, and annual additions over the forecast period from 1978 to 2000 are illustrated in Figures 2-1, 2-2 and 2-3. Estimates of ultimate potential are compared in Table 2-3.

AERCB

AERCB submitted an estimate of total reserves additions of 23.6 Tcf to the year 1995 based on its ultimate potential estimate of 110 Tcf for Alberta. It stated however, tha the relatively high reserves growth over the last few years and the optimistic reports from certain segments of the industry respecting the potential of recent discoveries raised the possibility that the ultimate potential in Alberta might exceed its current estimate. It is to examine the province's ultimate gas potential at a hearing in February 1979. For illustrative purposes AERCB included a forecast of total reserves additions of 33.4 Tcf to 1995, based on an ultimate potential of 130 Tcf.

Although future discoveries would probably involve smaller, less productive reserves, AERCB considered that geological prospects in Alberta remain good.

Saskatchewan

Saskatchewan regarded reserves additions as being the

Table 2-2

MARKETABLE NATURAL GAS RESERVES ADDITIONS FORECASTS
CONVENTIONAL PRODUCING AREAS
1978-2000
(Tcf @ 1000 Btu/cf)

	B.C.	Alberta	Sask.	Southern Territories	Western Canada Total	Ontario & Other Eastern Canada	Canada Total
AERCB (110 Tcf Case)[1]	—	23.6	—	—	—	—	—
AERCB (Illustrative 130 Tcf Case)[1]	—	33.4	—	—	—	—	—
Saskatchewan[2]	—	—	1.0	—	—	—	—
British Columbia[2]	7.7	—	—	—	—	—	—
AGTL (Case 1)	4.3	46.9	5.0	—	56.2	—	—
AGTL (Case 2)	5.5	58.8	6.1	—	70.4	—	—
AGTL (Case 3)	8.6	86.4	8.6	—	103.6	—	—
Alberta & Southern[3]	5.4	46.4	—	—	—	—	—
Amoco	—	83.4	—	—	—	—	—
CPA (Illustrative high case)[4]	—	—	—	—	—	—	92.0
CPA (Illustrative low case)[4]	—	—	—	—	—	—	46.0
Dome	—	—	—	—	—	—	69.3
Gulf[2]	13.2	31.2	0.7	—	45.1	0.2	45.3
Home	—	—	—	—	62.6	—	—
Imperial	5.3	22.7	1.2	1.5	—	—	30.7
IPAC	—	—	—	—	—	—	58.0
Norcen (Additional markets case)	—	—	—	—	—	—	41.9
Norcen (No additional markets case)	—	—	—	—	—	—	39.3
PanCanadian[2]	5.2	45.1	1.0	1.2	—	—	52.5
Polar Gas (Case 1)[2]	6.5[8]	28.1	0.8	—	—	—	35.4
Polar Gas (Case 2)[2]	6.5[8]	25.5	0.8	—	—	—	32.8
Polar Gas (Case 3)[2]	6.5[8]	27.9	0.8	—	—	—	35.2
ProGas	—	—	—	—	—	—	49.5
Shell	6.1[5]	24.7[5]	1.0[5]	—	31.8[5]	—	39.7[7]
TransCanada (Min.)	10.4	29.6	0.8	—	40.8	0.2	41.0
TransCanada (Max.)	10.4	46.8	0.8	—	58.0	0.2	58.2
Westcoast[3,6]	7.4	—	—	—	—	—	—
NEB (High Case)	6.0[8]	40.0	1.0	—	—	—	47.0
NEB (Expected Case)	6.0[8]	31.0	1.0	—	—	—	38.0
NEB (Low Case)	6.0[8]	22.0	1.0	—	—	—	29.0

Note: (1)Reserves additions to 1995.
(2)Tcf @ 14.65 psia and 60° F.
(3)Tcf @ 14.73 psia and 60° F.
(4)Includes frontier additions.
(5)New discoveries only.
(6)Reserves additions to 1997.
(7)Includes appreciation of existing reserves.
(8)Includes southern Territories.

Table 2–3

ULTIMATE POTENTIAL ESTIMATES OF MARKETABLE GAS CONVENTIONAL PRODUCING AREAS

(Tcf @ 1000 Btu/cf)

	British Columbia	Alberta	Sask.	Southern Territories	Western Canada Total	Ontario & Other Eastern Canada	Canada Total
AERCB	—	110	—	—	—	—	—
British Columbia[2]	18.5	—	—	—	—	—	—
BCPC[2] [3]	30	—	—	—	—	—	—
AGTL	—	—	—	—	169-204-234	—	—
Alberta & Southern[1]	17[5]	130	—	—	—	—	—
Amoco	—	204	—	—	—	—	—
Dome	—	—	—	—	180	—	—
Gulf[2]	30	105	3	—	138	5	143
Home	—	—	—	—	170	—	—
HBOG	15	130	3	1	149	1	150
Imperial	19	114	3	3	139	1	140
IPAC	—	—	—	—	180	—	—
Mobil	28	130	—	—	—	—	—
PanCanadian	28.8	195.1	3.2	4.8	231.9	—	—
TransCanada	—	110-130[5]	—	—	—	—	—
Westcoast	20-30	—	—	—	—	—	—
NEB	18[4]	105-125-135	3	—	126-146-156	1	127-147-157

[1] Tcf @ 14.73 psia and 60°F.
[2] Tcf @ 14.65 psia and 60°F.
[3] Raw Recoverable Gas
[4] Includes southern Territories.
[5] To year 2000.

transfer of probable reserves of natural gas into the proven category over time. It estimated the probable initial marketable gas reserves of Saskatchewan to be 1.2 Tcf, of which 0.9 Tcf were attributable to the Milk River zone. Reserves additions were forecast to be 1 Tcf from 1978 to 2000.

British Columbia

British Columbia estimated that an additional 9 Tcf of raw gas would be added to the initial marketable reserves of the province by the year 2000. This together with 13 Tcf discovered, amounted to an ultimate potential of 22 Tcf of raw gas or approximately 18.5 Tcf of marketable gas. It estimated that approximately two-thirds of the recoverable gas reserves would come from the plains region, specifically the Middle Devonian strata of the Fort Nelson area, the Triassic Doig and Halfway formations in the southern part of the Peace River Block and in the northwest extension of the Alberta Elmworth Lower Cretaceous trend. The remaining one-third of the total was allocated to the foothills region which was considered to offer excellent potential for the discovery and development of new reserves.

British Columbia did not include in its estimates of reserves additions and ultimate potential any gas that might occur in the tight sands in the British Columbia sector of the Deep Basin. It indicated that firm projections of potential from this area would be premature because of the early stage of drilling, the unique characteristics of the basin's reservoirs and the unknown cost of producing the gas.

In a study contained in British Columbia's submission, BCPC stated that the pace of exploration, amount of revenue from land sales, increasing number of producers participating in the activity, number of gas purchase contracts signed and pipeline processing facilities constructed were indicative of the prospects for discovering and developing new gas reserves in the province. It estimated the ultimate potential for British Columbia to be 30 Tcf in

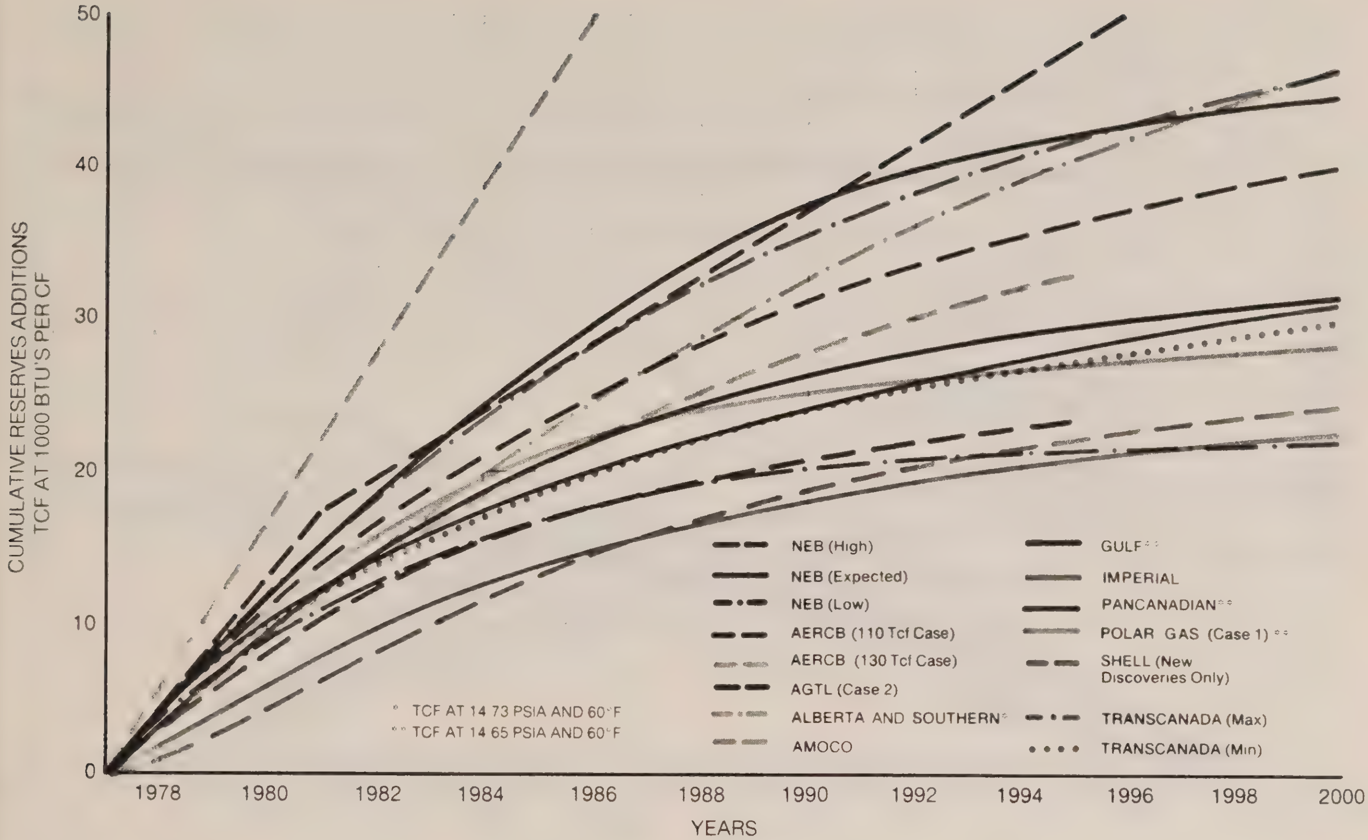


Figure 2-1 **FORECAST GROWTH OF MARKETABLE RESERVES FROM RESERVES ADDITIONS IN ALBERTA**

terms of raw recoverable gas. This total was based on individual estimates of potential as follows: Cretaceous strata 4.5 Tcf, Triassic and Permo-Pennsylvanian strata 8.5 Tcf, Mississippian and Upper Devonian strata 6.2 Tcf and Middle Devonian strata 10.8 Tcf. The 30 Tcf raw recoverable gas would convert to an ultimate potential in terms of marketable gas of approximately 25.5 Tcf. BCPC indicated that it had included in its assessment the gas in the low permeability sediments of the Deep Basin.

AGTL

AGTL, in forecasting its annual reserves additions, utilized data prepared for it and Sulpetro of Canada Ltd. jointly by C.R. Winter Associates Ltd., which provided information on the undiscovered reserves potential of the Western Canadian Sedimentary Basin and a forecast of reserves additions. AGTL generated three supply forecast cases for western Canada using reserves additions rates of 2, 2.6 and 4 Tcf per year on the basis of corresponding undiscovered potential estimates of 65, 100 and 130 Tcf. Combining the undiscovered potential with the 94 Tcf already found and with 10 Tcf attributable to appreciation of existing reserves resulted in 169, 204, and 234 Tcf as estimates of ultimate potential for western Canada. AGTL's previous estimate contained in its submission to the Northern Pipelines hearing was 121.2 Tcf.

To estimate the undiscovered gas reserves potential, AGTL's consultants, C.R. Winter Associates, used a statistical approach whereby a random sample of 522 abandoned wells was taken from western Canada's 40,000 exploratory wells. Statistical parameters of the sample wells, combined with log analyses, were used to estimate undiscovered gas reserves potential and probable deliverability.

Alberta and Southern

Alberta and Southern used the AERCB initial reserves value of 80.5 Tcf as of 31 December 1977 and estimated that these reserves would appreciate by 14.6 Tcf to 95.1

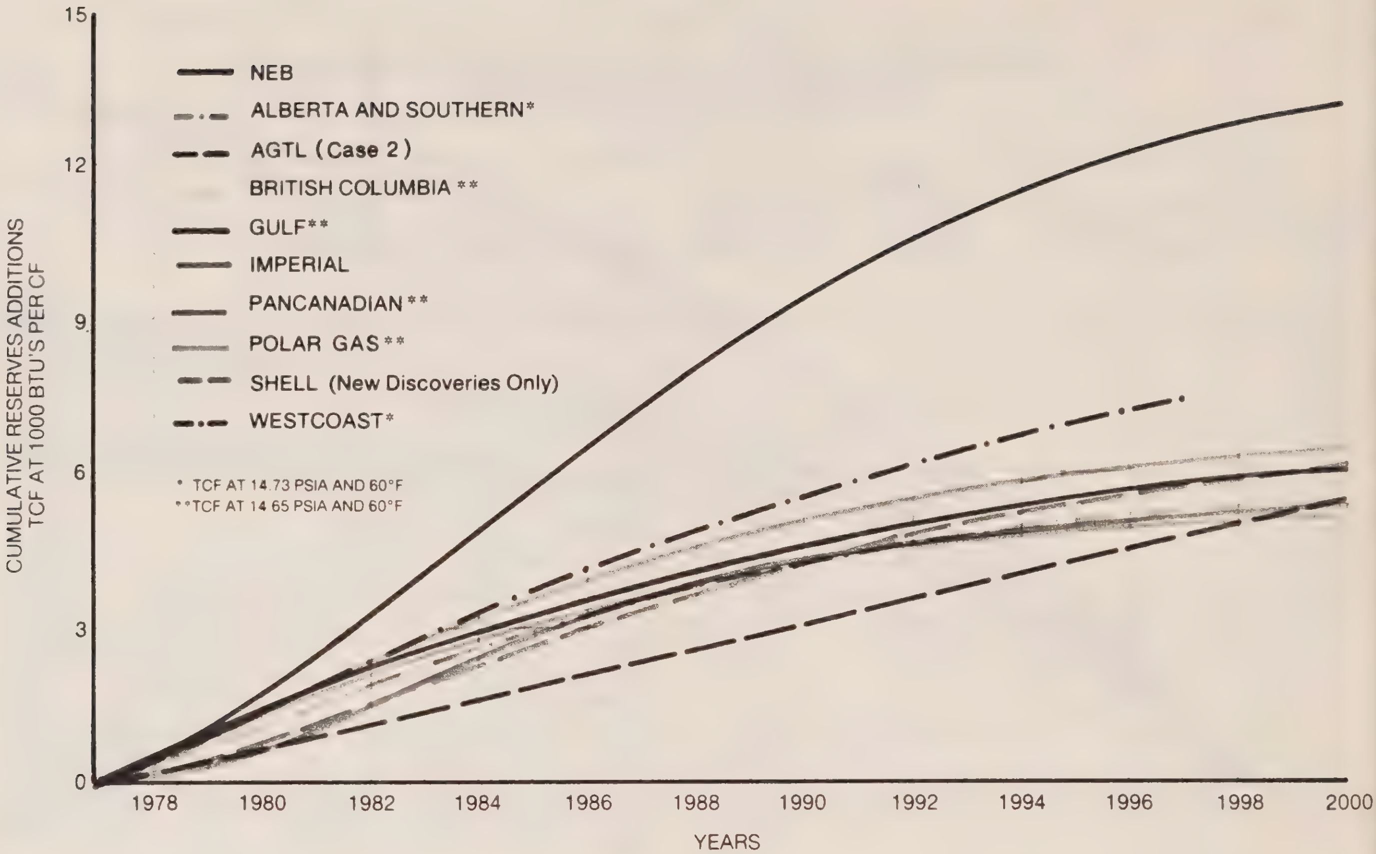


Figure 2-2 **FORECAST GROWTH OF MARKETABLE RESERVES FROM RESERVES ADDITIONS IN BRITISH COLUMBIA**

Tcf. Based on projections of historical finding rates, it anticipated that future discoveries would amount to some 31.8 Tcf during the forecast period to give Alberta a total of approximately 46.4 Tcf in additions, and an initial marketable reserve of 127 Tcf by the year 2000. Future growth and further discoveries beyond that date would yield an ultimate reserves base of at least 130 Tcf. Alberta and Southern expected British Columbia's marketable reserves to grow by some 0.4 Tcf per year for the next four years, declining thereafter to yield about 5.4 Tcf of reserves additions by the year 2000. No reserves growth was forecast for Saskatchewan.

Amoco

Amoco estimated the ultimate potential of conventionally producible gas in Alberta to be 204 Tcf. This estimate did not include gas in the low permeability sediments of the Deep Basin. However, Amoco indicated that an assessment of ultimate potential should include an evaluation of those deposits known to exist.

With respect to reserves additions, Amoco indicated that the forecast rate of 5.5 Tcf per year would prevail for the next eight years up to 1985, and would then decline at 10 percent per year for a total of 83.4 Tcf by the year 2000.

CPA

CPA indicated that it believed most producers were extremely optimistic concerning the level of expected future gas reserves additions. For illustrative purposes it adopted a range of reserves additions from 2 to 4 Tcf annually, based on recent historical reserves additions rates for the producing areas plus the Mackenzie Delta-Beaufort Sea area and the Arctic Islands. These estimates were presented for the purpose of illustrating its proposed method of determining surpluses. For the forecast period 1978 to 2000, total reserves additions for the low case were 46 Tcf and for the high case 92 Tcf.

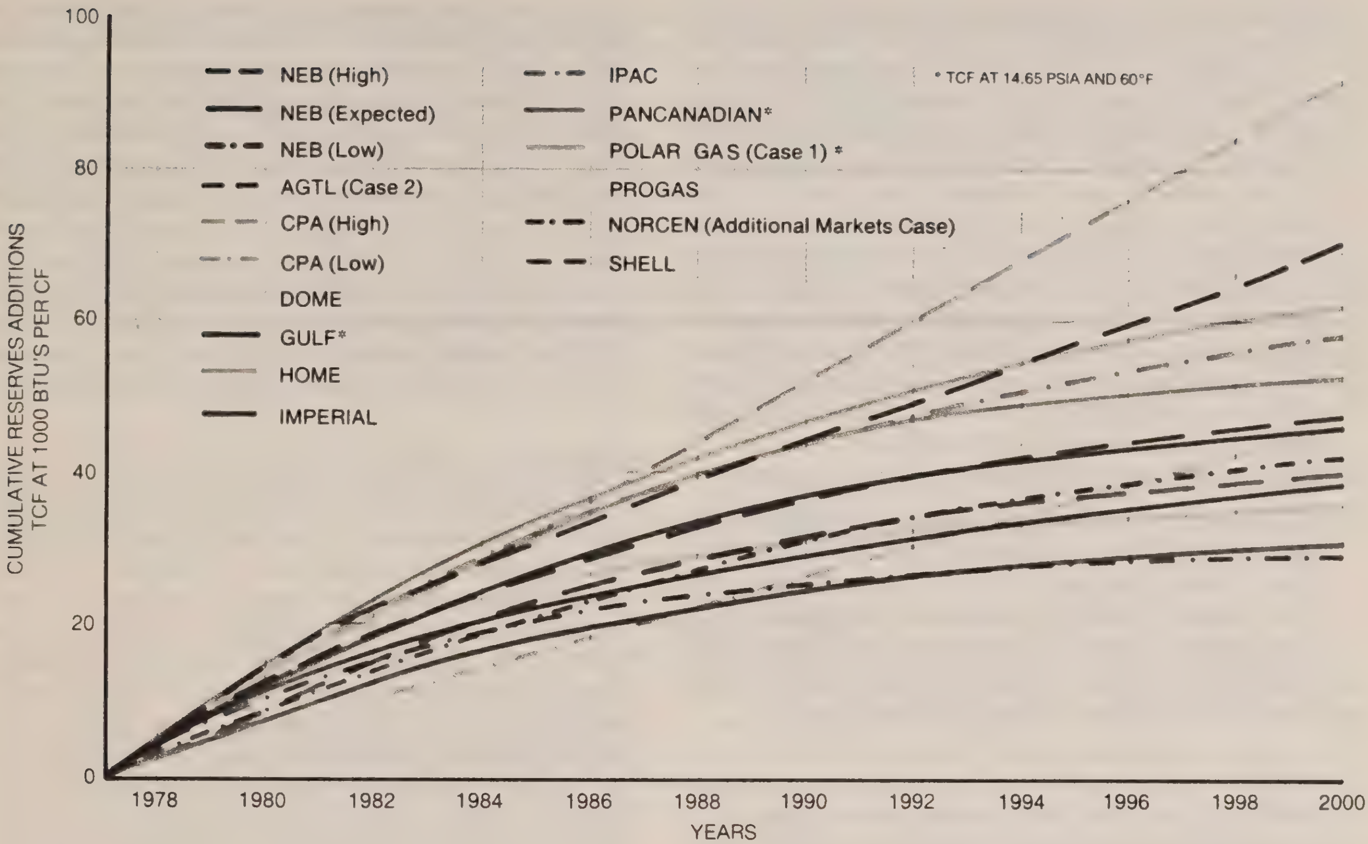


Figure 2-3 **FORECAST GROWTH OF MARKETABLE RESERVES FROM RESERVES ADDITIONS IN CONVENTIONAL PRODUCING AREAS**

CPA indicated that it had not made an estimate of the ultimate potential of the conventional areas of Canada.

Dome

Dome stated that if suitable markets were available and there were no dramatic improvements in producer economics, trend additions would be 5 Tcf in 1978, then would decline at an average of 5 percent annually. Over the forecast period 1978 to 2000 Dome expected 69.3 Tcf of marketable reserves additions for the conventional areas.

Dome estimated the minimum ultimate potential of the conventional areas of western Canada to be 180 Tcf, based on an independent assessment of published ultimate potential estimates and regional geological evaluations prepared for it by Kloepfer and Associates Ltd. Dome added a potential of 2 Tcf for the southern Territories to the consultant's estimate of 178 Tcf to arrive at its minimum of 180 Tcf ultimate potential. Dome expected this potential would be attained within a 30 to 40 year period.

The consultant's approach to deriving estimates of ultimate potential was based on two concepts, firstly, volume of sediments and yield factors, and secondly, extrapolation of past finding rates. Finally, a "best guess" estimate was used after considering estimates from the two methods employed.

Gulf

Gulf's reserves additions forecast was based on the assumption that current exploration and development activity would continue, the development activity predicated on availability of gas markets. The company estimated that during the forecast period 1978 to 2000 the additions

would be 13.2 Tcf for British Columbia, 31.2 Tcf for Alberta, 0.7 Tcf for Saskatchewan and 0.2 Tcf for eastern Canada for a total of 45.3 Tcf for all conventional areas. Gulf estimated that a total of 34 Tcf, including the 31.2 Tcf additions to the year 2000, was yet to be added in Alberta, of which 9 Tcf would come from shallow horizons and 25 Tcf from deeper zones. In British Columbia 19 Tcf remained to be found, which included the 13.2 Tcf additions to the year 2000, of which 5 Tcf would be from shallow depths and 14 Tcf from depths over 5,000 feet. Gulf stated that since British Columbia experienced approximately a 50 percent increase in drilling in 1978 over 1977, there should be an increase in additions during the next several years. Most of the additions for Saskatchewan would come from shallow zones.

Gulf estimated the ultimate potential of all conventional areas to be 143 Tcf, comprised of 105 Tcf for Alberta, 30 Tcf for British Columbia, 3 Tcf for Saskatchewan and 5 Tcf for eastern Canada. Its estimates were based on an analysis of the volume of sediments, hydrocarbon yield factors and gas tendency. It also incorporated knowledge gained from seismic and drilling operations.

Gulf indicated that its estimate of ultimate potential for Alberta might prove to be conservative and suggested, on the basis of a preliminary study, that 130 Tcf would probably be more appropriate taking into consideration developments in the Elmworth area, although it did not wish to commit to that figure.

Home

Home submitted that a mean value of 73 Tcf was expected to be found over the next 36 years in Western Canada. Within the forecast period 1978 to 2000 Home expected that 62.6 Tcf would be added. The company estimated the ultimate potential for western Canada to be 170 Tcf. For its estimate, Home updated estimates contained in Report EP 77-1 of the Department of Energy, Mines and Resources. It further adjusted the EMR estimates for net additions to year-end 1977. Home's estimate reflected an upward revision of potential of the Upper Mannville and foothills exploration plays, but did not include gas in the very low permeability sediments of the Deep Basin. Home indicated that of the 170 Tcf ultimate potential for western Canada, 21 Tcf were attributable to the Deep Basin that it believed could be produced by conventional means.

HBOG

HBOG did not submit estimates of annual additions for the conventional areas. It indicated that an ultimate potential of approximately 130 Tcf might be expected for Alberta. This was based on its own assessment using most probable projections of various statistical trends in exploration. The company stated that the Deep Basin play in Alberta raised the possibility that Alberta's ultimate potential could be much greater than the 130 Tcf. It included anticipated volumes from conventional reservoirs in the Deep Basin but did not consider very low permeability sediments in its estimates. HBOG adopted the NEB's previous ultimate potential estimates of 15 Tcf for British Columbia, 3 Tcf for Saskatchewan and 1 Tcf each for the southern Territories and Ontario, for a Canadian total of 150 Tcf.

Imperial

Imperial submitted a forecast of annual reserves additions based on its estimate of an ultimate potential of 140 Tcf for all Canada. It estimated that of a total of 30.7 Tcf of marketable reserves to be added by the year 2000, 25.2 Tcf would come from new discoveries, 5 Tcf from appreciation of discovered pools, and 0.5 Tcf from solution gas associated with future oil discoveries. Imperial indicated that the forecast of additions did not include the very large volumes of gas believed to exist in formations of low porosity and permeability in the Deep Basin area of Alberta and British Columbia. Imperial submitted that higher prices and new well-completion technology would be needed to achieve any large-scale recovery from this non-conventional resource.

Imperial increased its estimate of ultimate potential for Alberta from a previous estimate of 97 Tcf to the current 114 Tcf. The high level of exploratory drilling, and accompanying success caused it to change its opinions about areas previously thought to be unproductive. The company also indicated that the estimate included about 6 to 7 Tcf in the Elmworth area which could be produced with current technology.

IPAC

On the assumption that there would be no lack of markets during the forecast period 1978 to 2000 IPAC estimated that reserves additions would be 5 Tcf in 1978, dropping to 2.1 Tcf by 1990 and to 1 Tcf by the year 2000. The resultant total additions by 2000 would be 58 Tcf.

Based on the perception of many IPAC members that previously accepted estimates of ultimate potential were too low, IPAC, with Dome's permission, reviewed the Kloepfer study prepared for Dome which indicated an ultimate potential in the order of 178 Tcf for western Canada. IPAC was of the opinion that a large contribution to any

future reserves would come from the foothills area of Alberta and British Columbia. Since IPAC considered the area to be in the early stages of development, it did not lend itself to the statistical method which had been employed by Kloepfer in other areas. It therefore commissioned Kloepfer to do a different type of study of the foothills area, based on analysis of structural traps. This study indicated that the ultimate potential of the foothills was 43 Tcf, whereas the results of Kloepfer's study for Dome indicated 23 Tcf as the potential for the foothills region. Kloepfer felt this represented a valid range of reasonable estimates, although the consultant did not claim that the 43 Tcf of gas was necessarily a maximum value.

Combining the results of the two studies, IPAC felt confident in its belief that western Canada's ultimate potential was in excess of 180 Tcf.

Mobil

Mobil referred to AERCB Report 78-E in which was presented, for illustrative purposes, a supply outlook based on a possible ultimate marketable gas potential of 130 Tcf. Mobil supported the 130 Tcf as a reasonable estimate on the basis of an analysis of basin potential from its own evaluation of recognized plays. The company estimated an ultimate potential for British Columbia of 28 Tcf, for a total of 158 Tcf for the two provinces.

Norcen

Norcen's gas reserves additions forecasts were comprised of new discoveries resulting from projected gas exploration footage drilled, appreciation of those new discoveries, and appreciation of gas reserves found prior to 1978.

Two schedules of additions were presented. The first assumed the availability of additional markets, thereby making prospects for new gas discoveries more favorable, which added 41.9 Tcf of reserves over the period 1978 to 2000. The second schedule, based on no additional markets being available, provided for reserves additions of 39.3 Tcf.

Norcen did not submit estimates of ultimate potential.

PanCanadian

According to PanCanadian, its concept of ultimate potential was the summation of its estimates of initial proved, probable and possible reserves. The company's assessment of current potential reflected its inability to estimate the probable and possible volumes with 100 percent confidence, hence it applied discount factors of 25 percent to its probable, and 75 percent to its possible estimate. It stated that additional drilling and development would increase the estimate of current potential towards the ultimate potential.

PanCanadian estimated that 30 June 1978 initial proved reserves of 97.8 Tcf had been found in the conventional areas, with 134.1 Tcf yet to be found, for an ultimate potential of 231.9 Tcf. Of this 231.9 Tcf, 147.0 Tcf would represent current potential. The company stated that 231.9 Tcf was the estimate to use for comparison with other submittors.

The company's forecast of reserves additions for the conventional areas during the forecast period 1978 to 2000 was 52.5 Tcf.

Polar Gas

Forecasts of reserves additions for the conventional producing areas were prepared for Polar Gas by John R. Lacey International Consultants. The additions for Alberta were submitted under three cases, each of which was predicated upon a level of industry activity in response to a particular economic climate. For Cases 1, 2 and 3, reserves additions for the period 1978 to 2000 were 28.1 Tcf, 25.5 Tcf, and 27.9 Tcf respectively. Only one estimate of 6.5 Tcf was submitted for British Columbia and the southern Territories. It was estimated that 0.8 Tcf would be added in Saskatchewan.

Total Canada additions to 2000 for the conventional areas were: Case 1–35.4 Tcf, Case 2–32.8 Tcf, and Case 3–35.2 Tcf.

ProGas

ProGas stated that the effort required to find oil and gas in a maturing area during a year normally increases with time, resulting in decreasing amounts of oil and gas to be found in the future. ProGas examined historical data with respect to the rate of decline in finding rates and chose a decline rate of 7.5 percent per annum which it applied to the 1977 additions of 4.82 Tcf. This approach by ProGas led to reserves additions for the conventional producing areas of 49.5 Tcf over the period 1978 to 2000. ProGas did not supply any estimate of ultimate potential of the conventional producing areas.

Shell

Shell's estimate of reserves additions was based on the

premise that 36 Tcf remained to be discovered in the conventional areas. Of this total, 28 Tcf were attributed to Alberta, 7 Tcf to British Columbia and the balance elsewhere, primarily in Saskatchewan. Utilizing historical drilling trends, success ratios and reserves discovered per successful wildcat drilled in Alberta and British Columbia, Shell projected its data to calculate an estimate of future annual discovery volumes, assuming an unlimited market. Shell indicated that initially the annual discovery volumes would average 3.4 Tcf, declining to 2 Tcf by 1984 and to some 0.3 Tcf by the year 2000, by which time 92 percent of the ultimate potential would have been found. Shell judgmentally segregated the annual discovery volumes into three reservoir classes. Some 27.5 Tcf were generally at deep and intermediate depths associated with comparatively high deliverability reservoirs. The remaining volume of 8.5 Tcf was from shallow reservoirs, mainly in Alberta and Saskatchewan. Shell's estimates of new discoveries during the 1978 to 2000 forecast period were 24.7 Tcf from Alberta, 6.1 Tcf from British Columbia, and 1 Tcf from other areas, mainly Saskatchewan. Appreciation of existing reserves would contribute 7.9 Tcf for total additions of 39.7 Tcf for all conventional areas.

TransCanada

TransCanada stated that ratios obtained by dividing AERCB reserves at successive year-ends by the cumulative gas well drilling mileages to those dates, would give a reasonable trend of reserves additions and ultimate potential.

The company submitted that assuming reasonable minimum and maximum drilling mileage on a year-to-year basis, ultimate potentials of 110 Tcf and 130 Tcf respectively would result by the year 2000. Both of these cases were used to develop its annual reserves additions.

TransCanada's reserves additions for Alberta from 1978 to 2000 were a minimum of 29.6 Tcf and a maximum of 46.8 Tcf. For British Columbia, the company used additions of 0.45 Tcf per year, a value previously used by Westcoast, to add 10.4 Tcf over the forecast period. It assigned additions of 0.2 Tcf for eastern Canada and 0.8 Tcf for Saskatchewan.

TransCanada's estimates of additions for the conventional areas in total were 41 Tcf for the minimum case, and 58.2 Tcf for the maximum.

Westcoast

Westcoast utilized the historical growth of proved initial pipeline gas during the period 1968 to 1977 to arrive at its estimates of annual reserves additions for British Columbia. The growth trend was determined by the least squares method from which the company concluded that the historical annual growth rate for British Columbia was approximately 490 Bcf. It assumed that this rate of 490 Bcf per year would continue for the next five years (1978 to 1982), after which it would decline at 5 percent per year.

Westcoast estimated that 7.4 Tcf would be added during the period 1978 to 1997. The company indicated that a continuation of this trend would give an ultimate potential of approximately 23.2 Tcf for British Columbia which would include the 11.6 Tcf found to the end of 1977.

The favorable geology of northeastern British Columbia, the extension of the Elmworth trend, foothills structures, Devonian reef trends and the potential of deeper zones in the Fort St. John area, led the company to forecast the ultimate potential of the province to be in the order of 20 to 30 Tcf.

Views of the Board

The wide range of forecasts of reserves additions submitted illustrates the diversity not only of informed opinion but also of the handling of data, the methodology used and the final interpretation of results. All estimates, whether optimistic or pessimistic, are important not only to the producer, transporter, distributor and consumer, but also to the various governmental agencies concerned with long-range energy resource planning.

The Board, in its August 1970 report to the Governor in Council related to applications of certain companies for the exportation of gas included a chart illustrating the growth of initial established reserves of natural gas from 1959 to 1969. Figure 2-4 is a reproduction of this chart, with data added to the end of 1978. The straight line on the original chart, representing gross additions to reserves of approximately 3.5 Tcf/year, has been extrapolated to demonstrate that it is possible to interpret reserves growth since 1969 as essentially unchanged from the level of the preceding 10 years. The higher additions rates in 1977 and 1978 are, of course, obvious, but it would be premature to conclude that these higher rates will necessarily continue over an extended period.

It should be recognized, in interpreting Figure 2-4, that substantially increased drilling effort was associated with the higher additions rates of 1977 and 1978. This is demonstrated in Table 2-4, in which is shown exploratory and development (excluding oil development) drilling footage

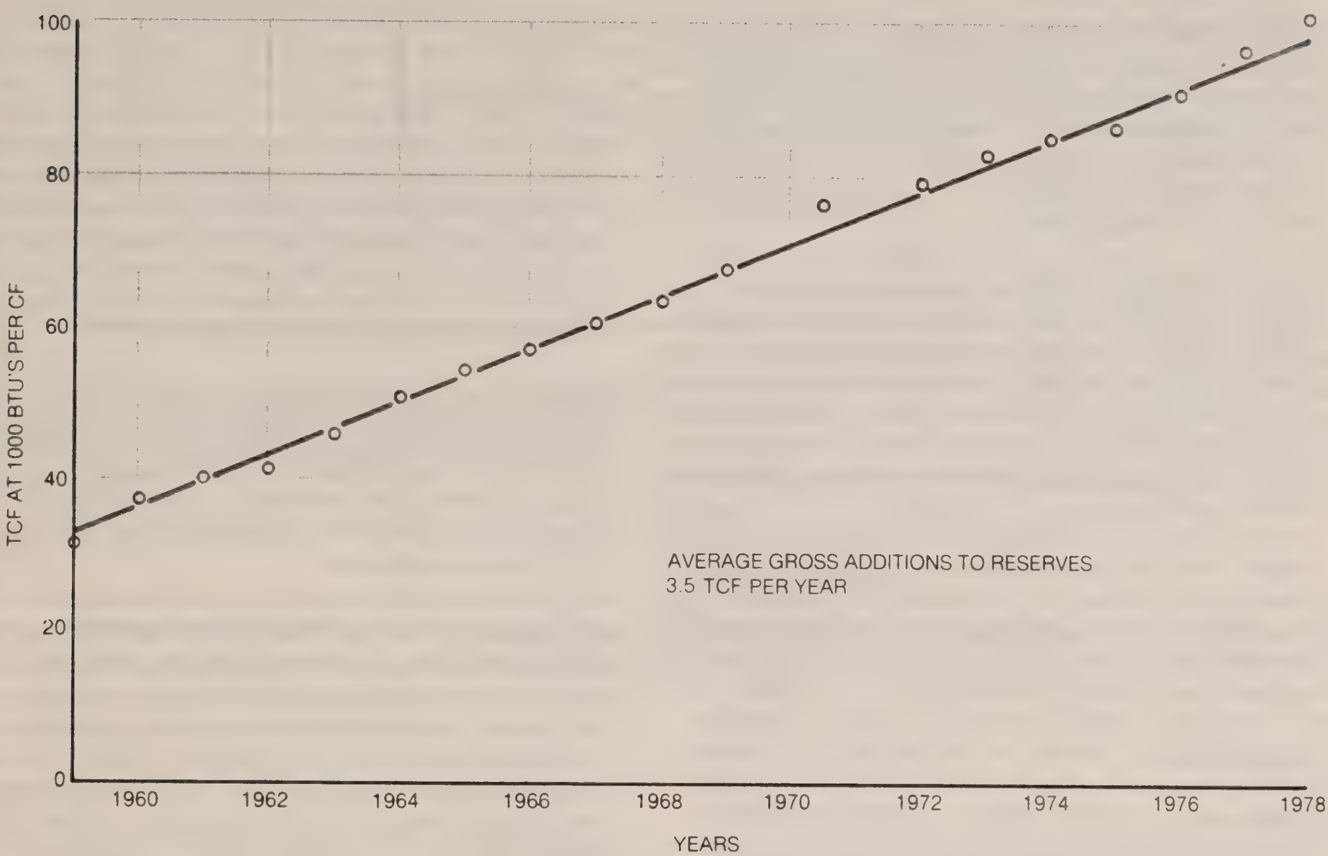


Figure 2-4 **INITIAL ESTABLISHED MARKETABLE RESERVES CONVENTIONAL PRODUCING AREAS (31/12/59 TO 31/12/78)**

for Alberta for the ten years ending in 1977. Data for 1978 are not yet available, but activity is expected to be slightly higher than in 1977.

Since it is not reasonable to expect the drilling activity in the conventional areas to be increased indefinitely, it follows that reserves additions will in due course decline. They are also constrained by the volumes of gas which remain to be found and developed. It is assumed in the Board's expected case forecast that reserves additions will be at or in excess of the historical level of some 3.5 Tcf until 1980, after which they will decline. Annual additions are projected to have decreased to approximately 1.8 Tcf by 1985, 1.2 Tcf by 1990 and 0.6 Tcf by 2000. Total reserves additions forecast for the period 1978 to 2000, expected case, are 38 Tcf. Low and high cases of 29 Tcf and 47 Tcf respectively are also presented, reflecting the Board's range of ultimate potential.

Table 2–4

EXPLORATORY AND DEVELOPMENT FOOTAGE IN ALBERTA

(Millions of feet)

	Exploratory	Development[1]	Total
1968	4.9	2.1	7.0
1969	4.8	2.3	7.1
1970	4.4	2.2	6.6
1971	4.3	2.5	6.8
1972	5.1	2.8	7.9
1973	5.9	4.3	10.2
1974	5.2	4.2	9.4
1975	4.8	4.7	9.5
1976	6.4	7.4	13.8
1977	7.6	7.1	14.7

[1] Excluding oil development footage
Data from CPA Statistical Yearbooks

The estimation of ultimate potential of natural gas is plagued with uncertainties regardless of the method employed. Excessive estimates can be as misleading as low estimates. The Board believes that ultimate potential cannot be quantified either mathematically or by the application of geological concepts with any great degree of certainty. Professional judgement plays a large part in any estimate of ultimate potential.

The Board studied different methodologies including statistics, play delineation, analysis of sedimentary patterns and field size distribution, along with an assessment of the detailed studies received from various submittors, and concludes that a finite numerical value of ultimate potential cannot be assigned with confidence. The Board therefore adopts a range of ultimate potentials for the conventional areas between 127 Tcf and 157 Tcf, with an expected value of 147 Tcf. This range of estimates is higher than the Board's estimate of 115 Tcf in its 1975 Gas Report, and the 120 Tcf estimate in its Northern Pipelines Report. This upward revision is based on a re-assessment of its own studies as well as evidence submitted at the inquiry.

Deep Basin

Introduction

During the inquiry considerable evidence was introduced regarding the gas potential of the Deep Basin area of Alberta and British Columbia. Accordingly, the Board is considering this area specifically in this section of this report. A definition of the Deep Basin has been included in the Glossary of Terms.

Views of Submittors

Amoco

Following an analysis of a 96-township area of the Deep Basin near Grande Prairie, Amoco concluded that the initial volume of natural gas in-place in the study area was 79 Tcf, of which only 4.6 Tcf could be conventionally produced. The bulk of the gas was contained within tight formations which would require massive hydraulic fracturing to achieve economic deliverability rates. Furthermore, Amoco stated that to date, its attempts to use massive hydraulic fracturing in the Grande Prairie area had been disappointing. It was confident that with proper design of fracturing programs, gas could be produced from the tight sands. The cost of the research and development of the fracturing techniques would be high and industry would require incentives which included guarantees of markets if the present level of expenditures were to be maintained.

Canadian Hunter

Canadian Hunter considered the entire Mesozoic section in the Deep Basin; with very limited exceptions, to be gas-saturated below a depth of about 3,500 feet. Within this gas-saturated section, much of the rock is of too low a permeability to be produced with conventional technology, but zones of better permeability do occur from which conventional production may be obtained.

Using the results of an analysis of 544 well logs from within the Deep Basin, Canadian Hunter concluded that at various levels of price and technology, 440 Tcf of gas could ultimately be recovered. Canadian Hunter estimated that at today's level of economics and technology, 50 Tcf were recoverable.

In one area of the Deep Basin, the Elmworth/Wapiti area, south and southwest of Grande Prairie, Canadian Hunter examined future potential in greater detail. Detailed analysis of logs, cores and tests from 57 wells within a 60-township area resulted in Canadian Hunter concluding that there was an initial volume in-place of over 60 Tcf. Of this volume, Canadian Hunter calculated that the industry should be able to recover over 40 Tcf. At today's cost/price relationship using conventional technology and well spacing, Canadian Hunter estimated that industry could recover 13 Tcf in 40 years. Of this, approximately 3.8 Tcf would come from conglomerates, 2.4 Tcf from other rock having porosity greater than 15 percent, 5.2 Tcf from 11 to 15 percent porosity rock and 1.7 Tcf from 7 to 11 percent porosity rock.

In its submission Canadian Hunter estimated existing reserves of the Elmworth/Wapiti area to be in the order of 383.6 Bcf proved plus 839.6 Bcf probable. During the inquiry, Canadian Hunter updated the estimates to 658.0 Bcf proved plus 1136.8 Bcf probable, as a result of additions to the reserves of the Falher conglomerate.

Based on a comparison of low permeability producing sands in the United States with the sands of the Deep Basin, Canadian Hunter concluded that it had not considered any rock of a quality which was not already producing in the United States in determining the 440 Tcf ultimate potential of the Deep Basin.

Dome

Kloepfer and Associates Ltd. was commissioned by Dome

to provide an estimate of the ultimate natural gas potential of western Canada. In the course of preparing this estimate, Kloepfer conducted a geological appraisal of the Elmworth/Wapiti area. Using information from 100 wells, including well logs, core data, and completion and stimulation details, Kloepfer estimated the established reserves of the area to be 2.2 Tcf. The analysis was limited to conventional reservoirs and no attempt was made to quantify gas in low permeability formations.

Gulf

During the inquiry Gulf indicated that it was considering an increase in its estimate of the ultimate potential of Alberta of 25 Tcf essentially to account for results from the Elmworth trend.

Home

Home estimated that 21 Tcf of its 170 Tcf ultimate potential estimate for western Canada were in the Deep Basin area. This volume included reserves in lower quality conventional reservoirs which Home considered recoverable under today's technology and economics.

Imperial

Imperial stated that while its initial interest in the Deep Basin was for gas in conventional reservoirs, gas in low permeability reservoirs might be a resource in the future and it would be exploring for both types.

PanCanadian

PanCanadian assessed the Deep Basin area of Alberta and estimated the initial proved reserves at 30 June 1978 to be 36.5 Tcf. The area involved, however, was larger than that usually defined as Deep Basin. The company estimated the ultimate potential of its Deep Basin to be 102.4 Tcf and the current potential 60.7 Tcf.

Polar Gas

Polar Gas consultant, John R. Lacey International Ltd., stated that it had undertaken an analysis of a portion of the Deep Basin in Alberta from approximately Township 64 to 74, Ranges 1 to 13 W6, which included the Elmworth/Wapiti area. This work was done for AGTL in support of an application by it to AERCB. The consultant concluded that the study area contained proved, probable and possible conventional reserves of 2.9 Tcf which could be recognized or projected at that time, of which 2.1 Tcf were in the Elmworth/Wapiti area itself. The potential for the study area to the year 2000 was considered to be in the order of 5-6 Tcf. Lacey stated that while he did not think there was any question that a large amount of gas was in the Elmworth area, it did not follow that it would be available to the market, or available at a rate which would give any protection to Canada's future needs.

British Columbia

British Columbia estimated the province's undiscovered conventionally recoverable raw gas reserves from the extension from Alberta of the Elmworth trend to be 0.9 Tcf. BCPC, assuming possible extension of the Elmworth play into the Dawson Creek area and continuing to the region northwest of Fort St. John, estimated the total raw gas potential of the British Columbia portion of the Deep Basin, including gas from low permeability sediments, to be 6.9 Tcf.

Views of the Board

Since much of the speculation on the potential of the Deep Basin is based on extrapolating the findings of studies undertaken in the Elmworth/Wapiti area, the Board undertook a study of that area. Based on evidence presented during the inquiry and its own study, the Board estimates that the currently established reserves of the Elmworth/Wapiti area are in the order of 1 Tcf, all in the Fahler conglomerate zones. The Board considers that the interest in this area and in fact the entire Deep Basin will continue and will likely result in increased established reserves during the next few years.

The Board accepts that large volumes of gas may well exist in the low permeability sands of the Deep Basin, however, they cannot be included as established reserves until technology is developed to permit the gas in these tight sands to be produced competitively with other energy forms in the market place. This conclusion would appear to be supported by industry as most submittors did not include gas from the low permeability sands of the Deep Basin in their schedules of reserves additions during the forecast period.

The Board is concerned that the publicity being given the Deep Basin, and particularly the view that it contains a potential in excess of 400 Tcf, may be misleading to the general public, who may wrongly assume that Canada has an additional reserve of this magnitude to serve its short and medium-term requirements.

Deliverability

Views of Submittors

Most of the producers making submissions to this inquiry provided estimates of natural gas deliverability from reserves which they control or of which they are the principal operator. These estimates varied from summaries of current maximum production capability of gas pools to detailed year-by-year production forecasts with an explanation of the underlying assumptions and methods of calculation.

Many submittors provided the Board with estimates of potential productive capacity of all reserves in the conventional producing regions of Canada. These forecasts are summarized in Table 2-5 and in Figure 2-5. All of the gas transmission companies provided estimates of deliverability from their reserves under contract. TransCanada provided a forecast of total productive capability of its contracted reserves as well as a forecast of total Canada productive capability. Alberta and Southern provided a forecast of deliverability to meet its own system requirements. Westcoast provided a pool-by-pool analysis along with an estimate of deliverability from trend gas additions in its supply area. Canadian-Montana provided a similar analysis of its system with pool-by-pool forecasts and projections of development drilling and new reserves additions in its supply area. SPC provided forecasts of total

Table 2–5

FORECASTS OF TOTAL CANADA GAS SUPPLY FROM CONVENTIONAL PRODUCING AREAS VIEWS OF SUBMITTORS

(Bcf/yr @ 1000 Btu/cf)

Year	1 AERCB* 110 Tcf Alberta Ultimate	2 AERCB* 130 Tcf Alberta Ultimate	3 Alberta and Southern	4 AGTL Case 1	5 AGTL Case 2	6 AGTL Case 3	7 Amoco with Deep Basin	8 Amoco from Conventional	9 CPA Case 1	10 CPA Case 2	11 Dome	12 Gulf*	13 Home
1978	3037	3037	3100	3493	3493	3493	3250	3250	2923	2923	3238	3010	3060
1979	3082	3082	3200	3700	3700	3700	3600	3600	3040	3040	3414	3020	3100
1980	3168	3178	3400	3898	3900	3905	4010	3970	3307	3307	3614	3106	3170
1981	3283	3313	3600	4112	4122	4151	4330	4290	3429	3429	3782	3154	3490
1982	3276	3316	3700	4251	4279	4353	4650	4610	3575	3675	3818	3174	3780
1983	3342	3402	3850	4429	4482	4624	5440	4930	3647	3847	3874	3308	3920
1984	3357	3427	3830	4426	4512	4740	5900	5070	3629	3929	3975	3344	4050
1985	3311	3401	3750	4480	4601	4920	6240	5120	3590	3990	4087	3349	4150
1986	3287	3387	3700	4493	4650	5060	6620	5220	3506	4006	4175	3348	4180
1987	3207	3327	3620	4562	4754	5256	6940	5410	3439	4039	4149	3348	4190
1988	3096	3246	3520	4531	4758	5352	7180	5460	3373	4073	4135	3314	4210
1989	2979	3149	3400	4430	4693	5379	7420	5500	3322	4122	4070	3286	4190
1990	2839	3029	3370	4327	4625	5403	7560	5500	3276	4176	4042	3258	4140
1991	2744	2964	3250	4195	4527	5397	7640	5450	3179	4179	3986	3194	4080
1992	2643	2893	3120	4071	4438	5399	7690	5370	3087	4177	3918	3133	4060
1993	2559	2829	3000	3973	4372	5418	7680	5250	3001	4172	3871	3052	3990
1994	2433	2723	2920	3806	4234	5353	7640	5110	2924	4168	3763	2950	3930
1995	2313	2633	2820	3627	4078	5262	7330	4950	2853	4162	3679	2849	3830
1996	N/A	N/A	2750	3464	3937	5175	6820	4780	2783	4151	3600	2745	3720
1997	N/A	N/A	2650	3335	3825	5109	6440	4570	2722	4143	3542	2646	3630
1998	N/A	N/A	2550	3214	3719	5043	6080	4340	2666	4135	3474	2552	3550
1999	N/A	N/A	2450	3071	3589	4946	5740	4170	2610	4122	3385	2423	3430
2000	N/A	N/A	2380	2974	3502	4888	5420	3890	2558	4110	3296	2316	3340

* 14.65 psia and 60°F (as is heating value)

deliverability available to its system under limited market and unlimited market assumptions.

AERCB

AERCB provided in its submission a detailed analysis of the potential productive capacity of reserves in the province of Alberta. This consisted of an analysis of the large connected pools (representing 80 percent of current production), small connected pools, large unconnected pools, small unconnected pools and trend gas additions. The analysis was prepared for an ultimate potential of 110 Tcf for Alberta. An illustrative presentation was also prepared assuming an ultimate potential of 130 Tcf for Alberta. AERCB adopted the NEB forecast for other producing regions as shown in the Northern Pipelines Report. AERCB's analysis demonstrated that Alberta's potential productive capacity would reach a maximum of some 3.05 Tcf/year in 1984 before decline commenced for the 110 Tcf ultimate case and would reach a maximum of some 3.15 Tcf/year in 1984 before decline commenced in the illustration of 130 Tcf ultimate potential.

Alberta and Southern and Canadian—Montana

Alberta and Southern and Canadian-Montana retained Manecon Associates to prepare a report covering various aspects of energy, one of which was a forecast of natural gas supply and demand. To prepare its forecast of maximum gas supply in Canada, Manecon employed the Al-

Table 2–5 (Cont.)

FORECASTS OF TOTAL CANADA GAS SUPPLY FROM CONVENTIONAL PRODUCING AREAS
VIEWS OF SUBMITTORS
(Bcf/yr @ 1000 Btu/cf)

Year	14 HBOG Unlimited Market	15 HBOG Limited Market	16 Imperial	17 IPAC	18 Norcen Existing Markets	19 Norcen Additional Markets	20 Pan Canadian	21 Polar Gas Case 1	22 Polar Gas Case 2	23 Polar Gas Case 3	24 ProGas	25 Shell	26 TCPL
1978	3136	3126	3140	3081	3070	3070	3074	3181	3181	3181	3035	3193	3300
1979	3191	3111	3240	3341	3170	3170	3148	3255	3252	3252	3237	3316	3440
1980	3296	3095	3320	3630	3280	3280	3309	3432	3400	3427	3439	3466	3557
1981	3409	3129	3380	3924	3370	3370	3476	3420	3415	3407	3624	3521	3629
1982	3390	3110	3410	3989	3360	3360	3507	3479	3450	3450	3592	3512	3606
1983	3464	3114	3460	4089	3350	3360	3553	3533	3484	3485	3606	3514	3633
1984	3517	3137	3400	4212	3330	3360	3545	3446	3397	3376	3630	3493	3669
1985	3519	3159	3390	4303	3290	3330	3543	3368	3268	3379	3642	3451	3642
1986	3543	3163	3390	4383	3230	3290	3570	3272	3154	3170	3659	3377	3649
1987	3502	3122	3340	4352	3200	3290	3587	3205	3054	3100	3602	3298	3625
1988	3449	3079	3280	4324	3140	3250	3562	3087	2914	2986	3613	3210	3574
1989	3371	3011	3200	4226	3030	3170	3529	2983	2783	2893	3543	3064	3505
1990	3270	2910	3070	4102	2920	3080	3510	2892	2693	2816	3393	2955	3454
1991	3216	2856	2960	3995	2860	3050	3461	2803	2601	2739	3281	2858	3441
1992	3165	2845	2880	3879	2810	3020	3435	2721	2521	2666	3168	2736	3400
1993	3112	2822	2790	3744	2780	3010	3398	2625	2431	2580	3081	2619	3295
1994	3007	2807	2690	3563	2730	2970	3326	2524	2339	2491	2919	2492	3158
1995	2918	2768	2610	3423	2680	2930	3247	2417	2242	2396	2794	2389	3034
1996	2822	2722	2530	3356	2640	2880	3163	2266	2104	2258	2672	2294	2973
1997	2732	2667	2490	3217	2590	2820	3057	2105	1957	2115	2548	2203	2905
1998	2632	2602	2390	3081	2530	2750	2943	1976	1845	1991	2461	2122	2816
1999	2549	2549	2280	2944	2460	2650	2814	1869	1757	1892	2351	2044	2726
2000	2447	2497	2190	2811	2390	2560	2676	1756	1663	1783	2245	1960	2638

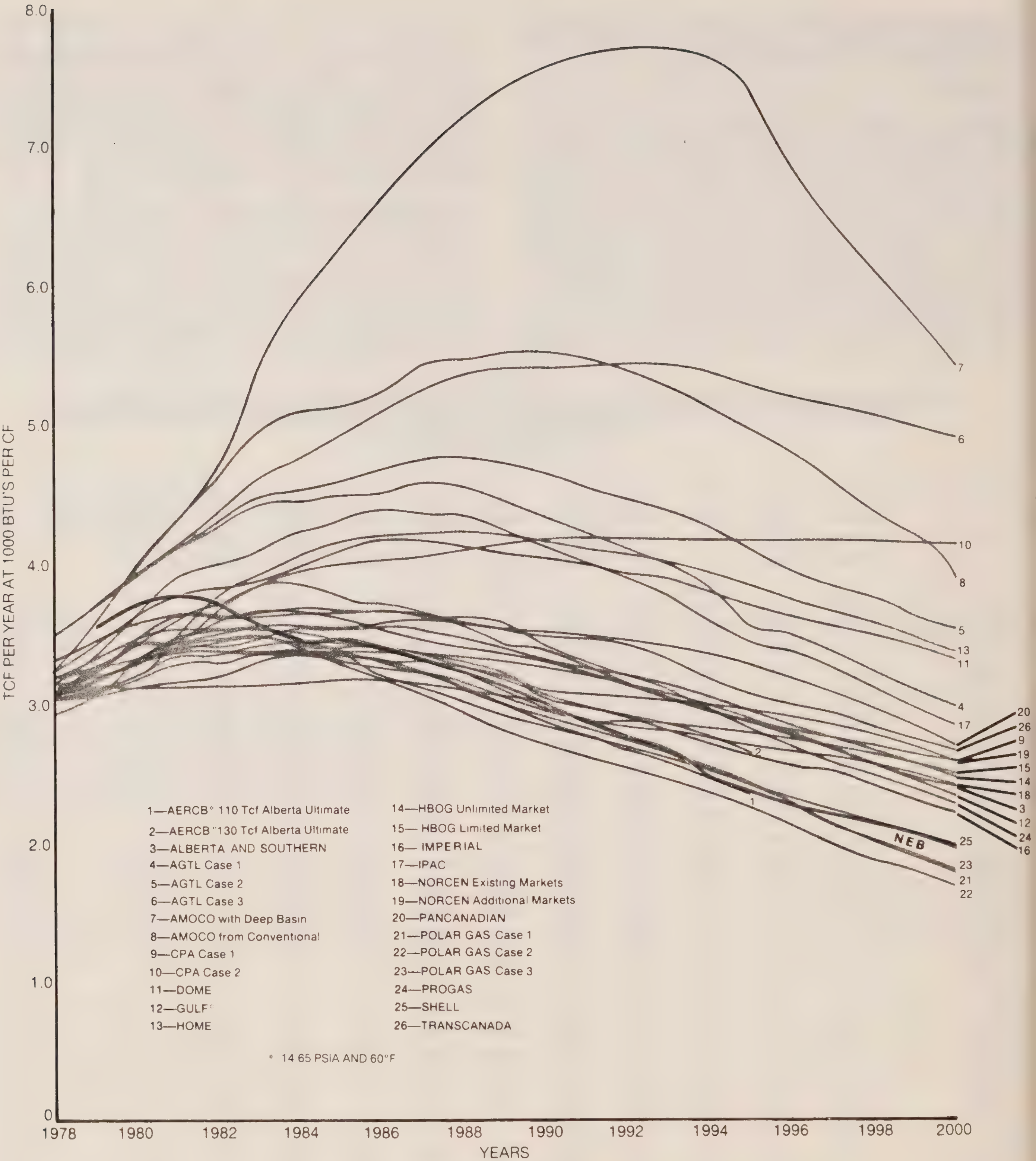


Figure 2-5 **TOTAL CANADA SUPPLY CAPABILITY FROM CONVENTIONAL AREAS**
Comparison Of Forecasts

berta and Southern computer model, which used year-end gas reserves as published by the provincial government agencies with supporting basic reservoir and deliverability data. The Alberta and Southern model projected a maximum production capability of some 3.1 Tcf in 1978 growing to approximately 3.85 Tcf by 1983 and declining thereafter to 2.38 Tcf by the year 2000.

AGTL

AGTL presented three "unconstrained" supply cases. Case 1 was based upon 65 Tcf of undiscovered gas potential with a constant 2 Tcf per year of reserves additions. Case 2 was based upon 100 Tcf of undiscovered gas potential with a constant 2.6 Tcf per year of reserves additions. Case 3 was based upon 130 Tcf of undiscovered gas potential with a constant rate of reserves additions of 4 Tcf per year. In each of these cases, the currently established gas reserves contributed deliverability in the same manner. The Alberta production forecasts were updates of forecasts prepared for the Northern Pipelines hearing. Forecasts for British Columbia, Yukon and Saskatchewan were prepared by Rehwald Consulting Services Limited. A description of each of the components of AGTL's forecast was presented in its submission. In Case 1, the forecast commenced with 3.49 Tcf/year in 1978, peaked at 4.56 Tcf in 1987 and declined thereafter to 2.97 Tcf by 2000. Cases 2 and 3 peaked at 4.76 Tcf and 5.42 Tcf in the years 1988 and 1993 respectively declining to 3.5 Tcf and 4.89 Tcf respectively by the year 2000.

Amoco

Amoco constructed a composite model of the Alberta connected reserves based on a rate-cumulative curve for a typical pool in Alberta. The basic profile was accumulated utilizing annual reserves increments of 2.9 Tcf (long-term average finding rate) to a total of 61.1 Tcf initial connected reserves in Alberta. The other established reserves in Alberta were connected over five years and produced according to the developed profile. Supply from the other provinces, as determined by CPA, was added to the total Alberta forecast as was Amoco's estimate for the Mackenzie Delta. A forecast of deliverability from reserves additions was based on additions of 5.45 Tcf per year for eight years, declining at 10 percent per year thereafter. Amoco's estimate of total Canada supply capability, excluding the Mackenzie Delta, commenced with 3.25 Tcf in 1978, peaked at 5.50 Tcf in 1989 and declined thereafter to 3.89 Tcf by the year 2000.

CPA

CPA carried out an industry survey of Alberta gas plant operators to obtain forecasts for 80 percent of current Alberta plant operations. Forecasts for other plants were estimated based on production history. PanCanadian's forecast for southeast Alberta shallow gas was adopted. CPA prepared its own forecasts for Alberta's deferred and unconnected reserves. The British Columbia forecast was based on a CPA submission to the B.C. Energy Commission's hearing of June, 1978. CPA prepared a Saskatchewan forecast based on a report by the Saskatchewan Natural Gas Development and Conservation Board augmented by producer forecasts for the later years. CPA employed producer forecasts for the southern Territories and prepared its own forecasts for the Mackenzie Delta-Beaufort Sea area and Arctic Islands. It estimated that western Canada could produce about 3.1 Tcf in 1978. The CPA presented two illustrative deliverability tests using reserves additions of 2 and 4 Tcf/year. Excluding the Delta-Beaufort supply, the first case illustrated deliverability of 2.92 Tcf in 1978 peaking in 1983 at approximately 3.65 Tcf then declining to 2.56 Tcf by 2000. Similarly the 4.0 Tcf/year additions case peaked in 1991 at approximately 4.18 Tcf and then declined to approximately 4.11 Tcf by the year 2000.

Dome

Dome accepted the Board's estimate of deliverability from total controlled reserves and Alberta uncommitted reserves as presented in the Northern Pipelines Report as a starting point for its forecast. Dome felt that the Board's estimates of established reserves and deliverability from deferred reserves were understated and accordingly adjusted the Board's forecasts. It then prepared its own forecast of deliverability from reserves additions and deliverability from the Mackenzie Delta-Beaufort Sea and Arctic Islands areas. Dome's forecast of total southern Canada deliverability commenced at 3.24 Tcf in 1978, peaked at approximately 4.18 Tcf in 1986 and then declined to 3.3 Tcf by the year 2000.

Gulf

Gulf presented a supply forecast which assumed no demand restrictions. Its Alberta forecast was developed from a review of submissions to the AERCB while those for other areas were derived from overall production profiles. Gulf used "aggressive" connection rates for unconnected reserves and reserves additions in British Columbia. Initial rates of take of 1:5750 (i.e. 1 MMcf/day for

each 5750 MMcf of reserves) for "shallow" gas and 1:7300 for "deep" gas were assumed. In Alberta, Gulf assumed initial rates of take of 1:4400 and 1:5750 for shallow gas reserves in southeast and northwest Alberta respectively, while deep gas reserves additions were produced with initial rates of take of 1:7300. Gulf's total conventional natural gas supply forecast commenced with 3.01 Tcf in 1978, peaked in 1985 at 3.35 Tcf and then declined to 2.32 Tcf by the year 2000.

Home

Home based its forecast of the potential productive capacity of western Canada largely on published data from the provincial authorities and the Northern Pipelines Report. The combined forecast for connected and unconnected reserves in Alberta was taken from AERCB Report 78-E. The productive capacities of British Columbia and Saskatchewan reserves were obtained from the Northern Pipelines Report. Home prepared its own forecast of production from its estimate of remaining reserves potential of 73 Tcf. Its forecast of total potential productive capacity commenced in 1978 at 3.06 Tcf, peaked in 1988 at 4.21 Tcf and then declined to 3.34 Tcf by the year 2000.

HBOG

HBOG presented two forecasts of natural gas deliverability from conventional areas assuming unlimited and limited markets respectively. Both cases used the AERCB Report 78-E for connected and unconnected reserves. However, the limited market case assumed a two-year delay in the deliverability from unconnected reserves. For conventional areas other than Alberta, HBOG used the NEB forecasts from the Northern Pipelines Report in both cases. HBOG developed its own forecasts for new reserves additions and the connection and deliverability of those reserves. Its forecast of deliverability from the conventional areas assuming an unlimited market commenced at 3.14 Tcf in 1978, peaked in 1986 at 3.54 Tcf and then declined to 2.45 Tcf by the year 2000. Similarly, the limited market case commenced with 3.13 Tcf in 1978, peaked in 1986 at 3.16 Tcf and declined to 2.50 Tcf by the year 2000.

Imperial

Imperial developed its forecasts of available supply of Canadian natural gas assuming an unlimited market for natural gas. Its forecasts did, however, take into account the usual practical limitations of development economics, available plant capacities and restrictions on volumes of gas produced in association with oil. Imperial's forecast from established producing reserves was developed by summing forecasts for the 175 largest pools. The remaining smaller pools were grouped according to similar characteristics and forecast by group. Imperial prepared development schedules for various categories of unconnected reserves in Alberta, British Columbia and the southern Territories. It assumed that these reserves would be produced at initial rates of take of 1:7300. Imperial converted its forecast of trend additions into a deliverability forecast with initial rates of take of 1:7300. It assumed delineation of each year's discovery over five years with production commencing three years after delineation on the average. Imperial's forecast of total natural gas producibility from western Canada commenced at 3.14 Tcf in 1978, peaked at 3.46 Tcf in 1983 and then declined to 2.19 Tcf by the year 2000.

IPAC

IPAC stated that there was currently an excess of supply over demand of about 221 Bcf per year in the TransCanada and Alberta and Southern systems based on take-or-pay cutbacks alone. IPAC used the NEB deliverability forecast from the Northern Pipelines Report as the base for its deliverability projection. IPAC adjusted the NEB's reserves base to that of the various provincial agencies and converted the net difference to a schedule of deliverability. To its total forecast of deliverability from currently established reserves IPAC added a deliverability forecast for its future reserves additions. IPAC's total forecast of deliverability commenced in 1978 at 3.08 Tcf, peaked in 1986 at 4.38 Tcf and then declined to 2.81 Tcf in the year 2000.

Norcen

Norcen adopted the forecasts of total Canada potential deliverability from existing reserves as published in AERCB Report 78-E. For gas found after 1977, Norcen assumed that the full volumes would be connected over ten years and would be produced at initial rates of 1:7300. Norcen presented two total Canada deliverability forecasts based upon its two finding rates related to discoveries under existing and additional market assumptions. Deliverability in both cases commenced at 3.07 Tcf in 1978, and peaked in 1981 at 3.37 Tcf. Deliverability declined to 2.56 Tcf by the year 2000 in the additional markets case whereas it declined to 2.39 Tcf in 2000 for the case with no additional markets.

PanCanadian

PanCanadian's forecasts of production from proved reserves were generally based upon forecasts prepared by government agencies. For Alberta, PanCanadian adopted

the AERCB's forecasts for large and small pools, whether connected or unconnected, as presented in AERCB Report 78-E. PanCanadian used its own forecast of production for southeast Alberta shallow gas. A detailed description of its shallow gas study was presented in its submission. For British Columbia, PanCanadian adopted a forecast prepared by the province's Ministry of Mines and Petroleum Resources for the B.C. Energy Commission hearing in June 1978. The southern Territories forecast was an Amoco forecast for the Pointed Mountain field. PanCanadian prepared a forecast for Saskatchewan reserves from data available from the Saskatchewan government. It also forecast supply from eastern Canada reserves based on CPA's estimate of reserves and historic production levels. PanCanadian's total non-frontier deliverability commenced at 3.07 Tcf in 1978, peaked in 1987 at 3.59 Tcf and subsequently declined to 2.68 Tcf by the year 2000.

Polar Gas

As a basis for its forecast of supply, Polar Gas assumed that demand was not a constraint. It chose to present three cases. The first case assumed that exploration activity would be maintained at current high levels. The second case assumed that exploration activity would decline while the third case assumed that exploration activity would decline with renewed high levels of activity beginning in the early 1980's. Polar Gas presented its supply forecast in two different ways – by province and by purchaser. Its forecast was done on a pool-by-pool field gate basis and included allowance for the connection of unconnected reserves, infill drilling and compression plus the addition of trend gas. Polar Gas' three cases of exploration activity applied most directly to Alberta for which three forecasts of trend additions were developed. The British Columbia trend additions were forecast only under the high exploration activity assumption. Polar Gas developed trend additions forecasts for 14 sub-areas in Alberta with different connection profiles for the new reserves in each area. Initial deliverability of the new reserves was based on 1:7300 contract assumptions which yielded initial rates of approximately 1:8400 when normal operational difficulties were considered. Flat life production varied from 3 to 13 years depending upon the area and quality of the reserves. Polar Gas' total Canadian gas supply forecast commenced at 3.18 Tcf in 1978 for all cases. Its forecast of supply peaked in 1983 at 3.53 Tcf in Case 1, 3.48 Tcf in Case 2, and 3.48 Tcf in Case 3. The supply then declined to 1.76 Tcf in Case 1, 1.66 Tcf in Case 2 and 1.78 Tcf in Case 3 in the year 2000. Polar Gas stated that it considered Case 1 to be its most likely supply forecast.

ProGas

The ProGas forecast of deliverability was based on an updating of the Northern Pipelines Report. The overall approach of its study was to adjust the NEB data to reflect changes that had occurred since the Board's study was prepared. The NEB forecast for total controlled and uncommitted Alberta reserves was accepted. To this base, ProGas added its forecast from deferred reserves and its forecast for reserves which it believed were not taken into account by the Board in the 1976 forecast. ProGas developed its own forecast of trend additions and connected these reserves over a period of 10 years following discovery. Deliverability from these reserves was forecast at a rate of 1:8400, chosen to reflect operating inabilities and the varying quality of reserves under a 1:7300 contractual arrangement. The total Canada deliverability forecast thus developed by ProGas commenced at a level of 3.04 Tcf in 1978, peaked in 1986 at 3.66 Tcf, and then declined to 2.25 Tcf by the year 2000.

Shell

Shell's forecast of full deliverability under no market constraint and continued high level activity was presented under three categories of reserves – existing, appreciation of existing, and new discoveries. Its forecast from appreciation of existing reserves was based on 9.8 Tcf of appreciation and its forecast of supply from new discoveries was based on a remaining potential of 36 Tcf of which 34 Tcf were forecast to be discovered and 28 Tcf to be developed and on stream by 2000. Shell's forecast of supply for TransCanada was taken from TransCanada's August 1977 application to AERCB, updated to include the Limestone Mountain and Elmworth fields. Shell's forecast for Westcoast was taken from Westcoast's submission to the B.C. Energy Commission inquiry of 30 May 1978. The other forecasts of deliverability from existing reserves were taken from the Northern Pipelines Report. Shell's total forecast of deliverability from the conventional areas commenced in 1978 at 3.19 Tcf, peaked in 1981 at 3.52 Tcf and then declined to 1.96 Tcf by the year 2000.

TransCanada

TransCanada estimated the capability of its own system on a collection point basis which it submitted represented the most realistic approach for appraisal of the net production characteristics of reservoirs, wells and gathering systems. In its assessment, no demand or pipeline facility constraints were imposed. TransCanada estimated total Canada supply capability by combining the detailed fore-

cast of its own system with forecasts of capability for Alberta and Southern, Westcoast, the major Alberta utilities, SPC, Canadian-Montana and eastern Canada obtained by direct contact with the respective companies. TransCanada projected supply for the smaller utilities in Alberta based on historical production. It also estimated Pan-Alberta's supply capability, the available capability from established uncommitted reserves in Alberta, the capability of deferred reserves in Alberta, and the available capability from TransCanada's forecast of trend gas additions in Alberta. The forecast of capability obtained from Westcoast included deliverability from British Columbia reserves additions. TransCanada's total Canada capability forecast commenced at 3.30 Tcf in 1978, peaked in 1984 at 3.67 Tcf and then declined to 2.64 Tcf by the year 2000.

Views of the Board

The Board employed its gas deliverability computer mode to forecast the maximum deliverability of gas for each o TransCanada, Alberta and Southern, Westcoast, an Pan-Alberta. The model performs a pool-by-pool analysi of gas deliverability as characterized by well flow charac teristics, basic reservoir parameters and daily contrac rates. The model utilizes drilling and compression cos data to determine the degree to which it would be eco nomic to maintain deliverability from a pool at the contrac rate by drilling infill wells and/or adding field compres sion. The computer model incorporates the produce forecasts for the solution and associated gas productio available to the appropriate gas transmission system. I should be noted that the Board assumed that blowdow

Table 2–6

NEB FORECAST OF TOTAL CONVENTIONAL SUPPLY CAPABILITY FROM CONTROLLED RESERVES

(Bcf/yr @ 1000 Btu/cf)

Year	TCPL	A & S	Westcoast	Westcoast GL–4	Pan–Alta.	Alberta Major	Utilities Minor	Many Islands	Canadian Montana	Prod'n East of Alberta	Total
1979	1789	579	424	57	63	366	49	36	16	73	3452
1980	1777	600	448	57	72	376	42	32	15	70	3489
1981	1745	582	456	57	66	377	46	28	14	66	3437
1982	1597	554	457	57	59	378	44	25	12	64	3248
1983	1438	533	427	15	53	347	42	22	14	62	2952
1984	1326	496	396	—	48	320	41	21	12	57	2717
1985	1240	464	382	—	44	339	41	19	12	52	2593
1986	1150	425	367	—	40	311	40	17	13	48	2411
1987	1067	391	350	—	37	294	37	15	13	44	2248
1988	981	363	324	—	34	273	32	14	13	39	2073
1989	905	325	298	—	32	252	28	12	9	34	1895
1990	825	302	245	—	28	236	25	11	11	32	1715
1991	731	281	193	—	24	222	22	10	10	28	1521
1992	657	250	184	—	21	218	20	9	9	25	1393
1993	600	213	166	—	18	205	18	8	8	24	1260
1994	498	153	146	—	16	192	15	7	7	19	1053
1995	442	139	143	—	14	176	14	7	6	19	960
1996	394	130	130	—	13	159	12	6	6	18	868
1997	361	121	122	—	12	144	11	5	5	17	798
1998	325	109	114	—	11	129	10	5	4	15	723
1999	293	98	107	—	9	116	9	4	4	14	654
2000	264	89	101	—	9	104	8	4	4	12	594

— Totals may not add due to rounding

would commence in the Kaybob South/Beaverhill Lake A pool cycling scheme in 1980, as suggested in evidence by the pool operators.

The remaining components of the gas supply forecast were derived from the following sources. The forecasts for the major and minor Alberta utilities in the Polar Gas submission were considered reasonable and were adopted. The Many Islands Pipelines and Saskatchewan production forecasts were adopted from the SPC submission. The Canadian-Montana forecast was adopted from Canadian-Montana's submission. The forecast of production from Ontario was estimated by the Board based on production history. The Board assumed that Westcoast would remove its annual authorized volumes under Licence No. GL-4 until the total licensed volumes had been removed.

A summary of the above-described forecasts is presented in Table 2-6 which represents a forecast of supply from controlled reserves.

Currently non-contracted gas in British Columbia was considered in the system analysis to be controlled by Westcoast. In Alberta the reserves not considered above were classified into five categories – shallow, uncommitted southeastern Alberta gas; shallow, uncommitted northwestern Alberta (Bluesky) gas; other uncommitted non-associated gas; deferred gas; and reserves beyond economic reach.

The Board estimates that there are some 2.3 Tcf of established uncommitted gas reserves in southeastern Alberta as of 31 December 1978. These reserves were assumed to be connected over a period of six years as shown in Table 2-7.

The deliverability from these reserves was based upon the historical data provided by the Kloepfer study in the Dome submission. Three distinct deliverability profiles were obtained for the southeastern Alberta shallow gas – Type A being for Milk River, comingled Milk River/Medicine Hat, and poor quality Medicine Hat reserves; Type B being for good quality Medicine Hat reserves; and Type C for 2nd White Specks reserves. The uncommitted southeastern Alberta shallow gas reserves were split into these three classifications according to the ratios provided in the Kloepfer study and were produced according to the submitted historical data.

In northwestern Alberta, the Board estimates that there are some 0.4 Tcf of uncommitted shallow (Bluesky) gas reserves. These reserves were assumed to be connected over four years as shown in Table 2-7 and were produced similarly to the Haro Bluesky pool as shown by TransCanada.

Table 2-7

CONNECTION RATES FOR UNCOMMITTED ALBERTA GAS
(percent)

Year	S.E. Alberta Shallow	N.W. Alberta Shallow	Other Non–Assoc.
1979	20	63	10
1980	26	25	14
1981	24	8	14
1982	16	4	15
1983	9	—	12
1984	5	—	9
1985	—	—	7
1986	—	—	6
1987	—	—	4
1988	—	—	3
1989	—	—	3
1990	—	—	1
1991	—	—	1
1992	—	—	1
Total	100	100	100

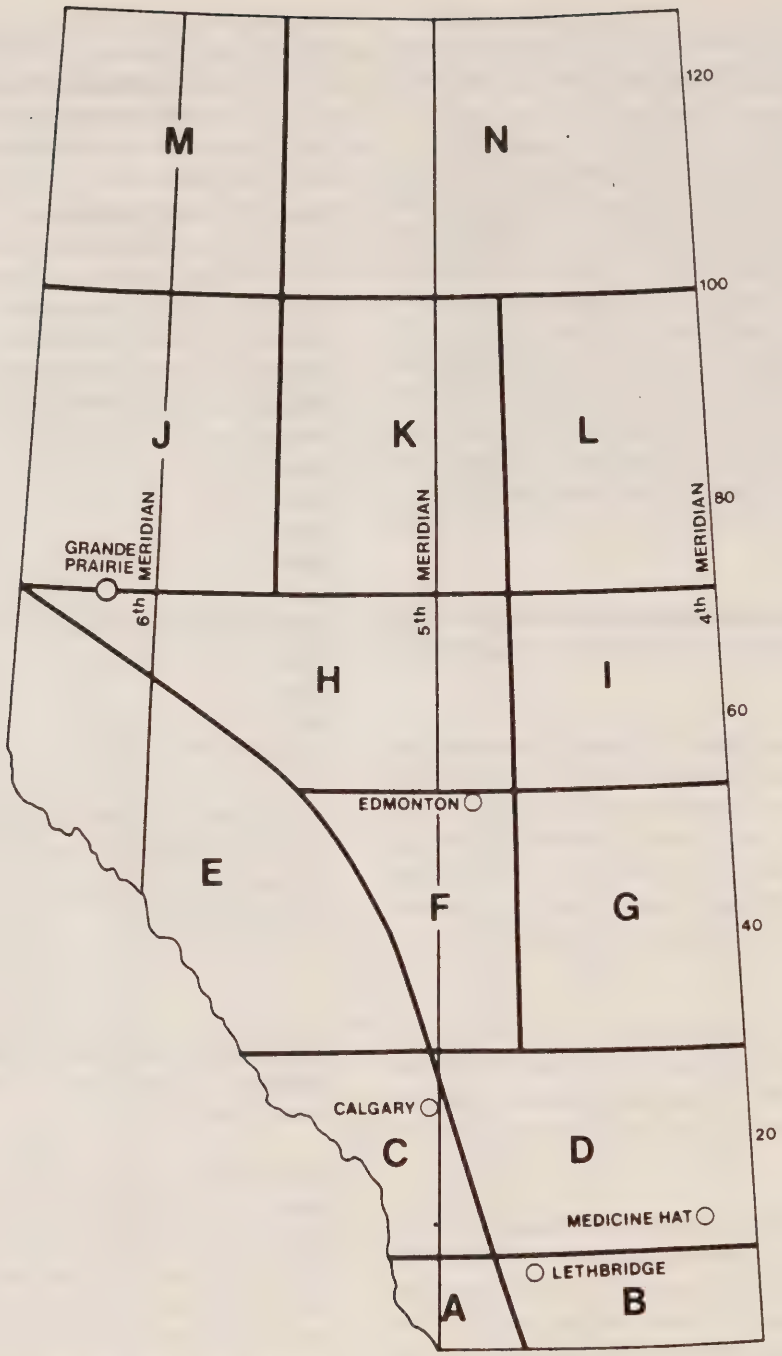
—Southeastern Alberta shallow and northwestern Alberta shallow based on evidence supplied by Imperial

—Other non-associated based on evidence supplied by TransCanada

The remainder of the uncommitted gas reserves, estimated by the Board to be 8 Tcf, were connected over 14 years as shown in Table 2-7. It should be noted that 65 percent of these reserves were assumed to be connected within five years. They were produced at an average annual rate of take of 1:7300 until 50 percent depletion and subsequently declined at 10 percent per year. This is believed to be an appropriate average annual rate of take for the mix of gas reserves in this category.

The Board estimates that there are some 4.2 Tcf of currently deferred gas reserves in Alberta. Production forecasts for the various deferred gas pools were prepared and the pools were connected at projected blowdown dates. Within 25 years, some 3.1 Tcf of these gas reserves were assumed to be connected.

The Board considers that the quantity of reserves pres-



NOTE: COURTESY OF POLAR GAS

Figure 2-6 **ALBERTA TREND RESERVES AREAS**

ently beyond economic reach is a dynamic one. AGTL is constantly expanding its gathering systems as aggressive drilling programs result in new proven reserves and the development of new gas fields. Due to these developments, certain wells considered beyond economic reach today may well be within economic reach tomorrow. Therefore, the Board feels that it is reasonable to consider that 50 percent of its estimate of 2.4 Tcf of gas reserves presently beyond economic reach would be available for production during the forecast period. These reserves were assumed to be connected at the rate of 4 percent per year beginning in 1979 and to be produced in a manner similar to the 8 Tcf of other uncommitted gas reserves.

The Board's forecast of reserves additions in Alberta was prorated amongst the areas shown in Figure 2-6 and these reserves additions were connected as shown in Table 2-8. The gas reserves connected in areas A, C and E were delivered at a rate of take of 1:7300 until 35 percent depletion and then declined at 7.7 percent per year thereafter. Gas reserves connected in the other areas of Alberta were expected to be of poorer reservoir quality and were consequently produced at 1:7300 until 10 percent depletion and then declined at 5.6 percent per year. Reserves additions in Saskatchewan were connected as shown in Table 2-8 and, as these reserves would most likely be of the shallow "Milk River" type, they were delivered following the same profile as southern Alberta Type A shallow gas reserves. The Board's forecast of British Columbia reserves additions were connected as shown in Table 2-8 and were delivered at the normal 1:5750 British Columbia contract rate with Westcoast's 13 percent "operational diversity" factor applied to it. These reserves produced at that rate until 65 percent depletion and declined at 15.8 percent per year therefafter.

The Board's estimate of total Canada supply capability commences with 3.5 Tcf in 1979, peaks at 3.8 Tcf in 1981, and declines thereafter to 1.9 Tcf by the year 2000. This forecast appears in Table 2-9 and is shown in Figure 2-7. It represents the Board's estimate of capability assuming no market constraints and therefore that the total capability volumes would be produced each year.

Table 2–8

CONNECTION RATES FOR RESERVES ADDITIONS

(percent)

Year after Discovery	British Columbia	Alberta Areas A,C,E	B	D,G,I	H,F	K,N	J,L,M,	Saskatchewan
1	10	5	15	15	5	—	10	15
2	10	5	15	15	5	5	10	15
3	10	5	25	25	20	5	20	25
4	25	15	15	10	20	20	10	10
5	25	20	10	5	15	20	10	5
6	5	15	10	5	5	15	10	5
7	5	5	5	5	5	5	5	5
8	5	5	5	5	5	5	5	5
9	5	5	—	5	5	5	5	5
10	—	5	—	5	5	5	5	5
11	—	5	—	5	5	5	5	5
12	—	5	—	—	5	5	5	—
13	—	5	—	—	—	5	—	—
TOTAL	100	100	100	100	100	100	100	100

— Alberta areas illustrated in Figure 2–6.

— Based on evidence submitted by Polar Gas.

Table 2–9

NATIONAL ENERGY BOARD FORECASTS OF TOTAL CONVENTIONAL SUPPLY CAPABILITY

(Bcf/yr @ 1000 Btu/cf)

	Supply Capability from Established Reserves						Supply from Reserves Additions			
Year	Total Controlled	Uncom-mitted Shallow	Other Uncom-mitted	B.E.R.	Deferred	Total	British Columbia	Alberta	Sask.	Total Canada Supply Capability
1979	3452	38	40	2	—	3533	—	—	—	3533
1980	3489	88	96	4	—	3677	3	14	1	3695
1981	3437	123	152	6	—	3718	8	42	1	3769
1982	3248	136	212	8	—	3604	15	90	2	3711
1983	2952	140	260	10	13	3376	28	153	3	3560
1984	2717	135	296	13	16	3176	47	224	4	3451
1985	2593	124	324	15	33	3089	66	295	5	3455
1986	2411	117	348	17	37	2930	84	358	6	3378
1987	2248	109	364	19	35	2774	104	416	9	3303
1988	2073	104	376	21	30	2604	123	471	11	3208
1989	1895	97	384	23	27	2426	141	524	14	3105
1990	1715	90	379	25	24	2233	157	575	16	2981
1991	1521	84	370	27	23	2025	172	620	18	2835
1992	1393	80	356	29	22	1879	186	657	20	2742
1993	1260	76	335	30	35	1736	198	685	22	2640
1994	1053	68	312	32	34	1499	209	705	24	2437
1995	960	63	289	33	34	1379	217	720	25	2341
1996	868	60	265	34	33	1260	222	731	27	2239
1997	798	58	242	35	54	1187	225	738	29	2179
1998	723	52	220	36	82	1113	225	741	30	2109
1999	654	48	201	37	81	1022	222	741	32	2017
2000	594	43	192	38	79	947	218	738	34	1937

—Totals may not add due to rounding

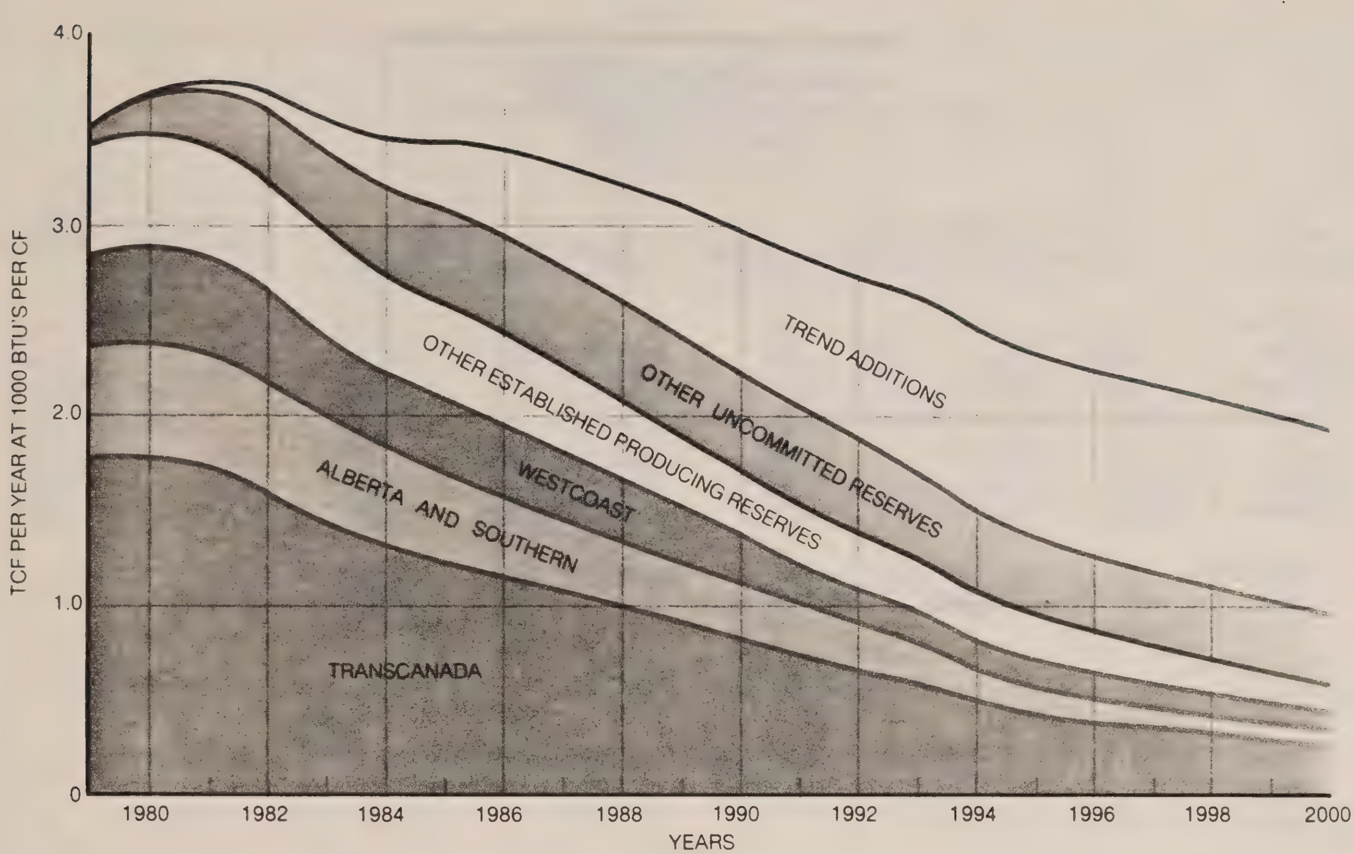


Figure 2-7 **SUPPLY CAPABILITY FROM CONVENTIONAL PRODUCING AREAS NEB Forecast**

FRONTIER AREAS

Established Reserves

Views of Submittors

While only Gulf and PanCanadian provided estimates of reserves for all the frontier areas, estimates of the reserves in one or two of the frontier areas were received from six other submittors. In preparing their estimates CPA, Gulf, Imperial, Panarctic, PanCanadian and Polar Gas undertook independent studies. The others, namely Dome and HBOG, adopted the NEB reserves estimates for the Mackenzie Delta-Beaufort Sea area contained in the Northern Pipelines Report. For the reserves of the Arctic Islands, Dome adopted the NEB estimate contained in the Northern Pipelines Report and HBOG adopted the estimate which Panarctic submitted to the Northern Pipelines hearing. The estimates of reserves in the frontier areas are compared in Table 2-10.

Panarctic submitted evidence in support of less rigid criteria than those employed in the conventional areas for the determination of the established reserves of the Arctic Islands. The Company stated that it was neither necessary nor possible financially to conduct the amount of delineation drilling characteristic of the conventional areas.

Views of the Board

Upon reviewing the evidence presented during the current inquiry, the Board noted the similarity between the reserves estimates for the frontier areas presented and those presented at the Northern Pipelines hearing. Based on this evidence and a review of its own studies, the Board finds no change required in its 1977 estimate of the established reserves of marketable gas in the Mackenzie Delta-Beaufort Sea area.

The Board has carefully considered the evidence presented by Panarctic and Polar with respect to criteria for

Table 2-10
ESTIMATES OF MARKETABLE NATURAL GAS DISCOVERED FRONTIER AREAS
(31/12/77)
(Tcf)

	CPA[1]	Dome[3]	Gulf[2]	HBOG[1]	Imperial[3]	Panarctic[1][4]	PanCanadian[2][6]	Polar Gas[1][4]	NEB[1] Established
Mackenzie Delta Beaufort Sea area	6.6	5.3	4.8	5.3	5.2	—	10.9	—	5.3[5]
Arctic Islands	10.3	7.3	10.3	11.3	—	12.0	12.5	10.7	9.2
East Coast Offshore	—	—	6.3	—	—	—	0.5	—	—
Territories (Other)	—	—	0.7	—	—	—	0.1[7]	—	—
Other Frontier Areas	—	—	—	—	—	—	0.3	—	—

[1] 14.73 psia and 60°F
[2] 14.65 psia and 60°F
[3] 1000 Btu/cf
[4] Proved and Probable
[5] Northern Pipelines Report
[6] Estimates to June 30, 1978
[7] North of latitude 64° only

determining established reserves of the Arctic Islands, and has concluded that its reservoir area factors can be increased without violating the requirement that established reserves be those interpreted to exist with reasonable certainty.

This action has had the effect of increasing the Board's established reserves of marketable gas in the Arctic Islands to 9.2 Tcf from 7.3 Tcf. Individual field estimates are shown in Table 2-11, compared with those of Panarctic and Polar Gas.

While the Board has studied basic data from wells drilled in the East Coast offshore areas it does not consider a meaningful estimate of established reserves is possible at this time.

Reserves Additions and Ultimate Potential

Views of Submittors

Forecasts of reserves additions and/or estimates of ultimate potential for the frontier areas were provided by nine submittors. While most of the estimates of ultimate potential were for the Mackenzie Delta-Beaufort Sea area and the Arctic Islands, Gulf and PanCanadian provided ultimate potential estimates for other frontier areas as well. Submittors' forecasts of reserves additions and ultimate potential are compared in Tables 2-12 and 2-13 respectively.

Table 2–11

COMPARISON OF ESTIMATES
RESERVES OF MARKETABLE NATURAL GAS
ARCTIC ISLANDS
(Tcf at 14.73 psia and 60°F)

	PANARCTIC[1]			POLAR GAS[2]				NEB[3]
	Prov. & Prob.	Possible	Total	Proved	Probable	Possible	Total	Established
Drake Point	5.252	.304	5.556	3.920	.148	.293	4.361	3.96
Hecla	3.575	.145	3.720	2.431	.277	.083	2.791	2.50
Kristoffer Bay	.653	.454	1.107	.629	.517	.077	1.223	.63
King Christian Is.	.588	NIL	.588	.632	.051	NIL	.683	.51
Jackson Bay	1.074	NIL	1.074	1.314	NIL	NIL	1.314	.94
Thor	.715	NIL	.715	.704	NIL	NIL	.704	.60
Wallis	.098	NIL	.098	.049	NIL	NIL	.049	.05
TOTAL	11.955	.903	12.858	9.679	.993	.453	11.125	9.19

(1) 30 August 1978
(2) 1 July 1978
(3) 31 December 1978

Table 2–12

RESERVES ADDITIONS FORECASTS
FRONTIER AREAS
1978 – 2000
(Tcf)

	Newfoundland & Labrador	Gulf[1]	HBOG	Imperial[2]	Panarctic[3]	Polar Gas
Mackenzie Delta Beaufort Sea Area	—	23	16.7	15[4]	—	—
Arctic Islands	—	16.5	32.7	16	10[5]	25-42
East Coast Offshore	18–40–150[6]	17.5	—	—	—	—
Territories Other	—	1	—	—	—	—

(1) 14.65 psia and 60°F
(2) 1000 Btu/cf
(3) 14.73 psia and 60°F
(4) To 1990 only
(5) To 1983 only
(6) 90%, 50% and 10% probability

Table 2–13

ULTIMATE POTENTIAL ESTIMATES
Frontier Areas
(Tcf)

	Dome[1]	Newfoundland & Labrador	Gulf	Home[1]	HBOG	Panarctic[2]	PanCanadian[3]	Geological[4] Survey of Canada EP 77–1
Mackenzie Delta–Beaufort Sea area	320	—	50	—	20–55	—	109.9	39–60–99
Arctic Islands	300	—	80	—	40–90	100	60.5	24–51–106[5]
East Coast Offshore	—	18–40–150[4][6]	71	30[7]	30–90	—	63.0	27–40–65[8]
Territories Other	—	—	9	—	—	—	4.1	6–10–20[9]
Other Frontier Areas	—	—	—	—	—	—	7.8	<1–2–12

[1]1000 Btu/cf
[2]14.73 psia & 60°F
[3]14.65 psia & 60°F
[4]90%, 50% & 10% probability
[5]excludes Northern Stable Platform area of southern Arctic Islands
[6]Newfoundland & Labrador's continental margin
[7]Labrador Shelf
[8]excludes "offshore inaccesible areas"
[9]includes southern Territories considered within the conventional areas.

Dome

Dome stated that the results of its recent exploratory activity in the Beaufort Sea supported the ultimate potential estimate of 320 Tcf for the Mackenzie Delta-Beaufort Sea area which it had submitted to the NEB for the Northern Pipelines hearing. Dome estimated the ultimate potential of the Arctic Islands to be approximately 300 Tcf.

Newfoundland

Newfoundland estimated the ultimate potential of the province's continental margins to be at least 18 Tcf at the 90 percent probability level, 40 Tcf at the 50 percent probability level and 150 Tcf at the 10 percent level. These estimates were expressed in terms of the amounts of gas perceived to be economically recoverable over the next 20 years. The estimates were stated to be the product of multidisciplinary team analysis which looked at all identified geophysical structures, using reservoir parameters derived from the nearest wells.

The provincial government recommended that the potential of the East Coast offshore should be considered in an assessment of Canadian supply within the time-frame of this inquiry.

Gulf

Gulf's estimates of ultimate potential in the frontier areas were based on an analysis of the volume of sediments, hydrocarbon yield factors and gas tendency of each basin. Incorporated into the analysis was knowledge gained from seismic surveys and drilling to date and from other basins with similar geological histories.

Gulf's forecast of reserves additions took into account the reserves potentials and the factors outlined above.

The ultimate potential for that part of the Northwest and Yukon Territories excepting the Mackenzie Delta-Beaufort Sea area was considered to be 9 Tcf, however, reserves additions were estimated to total only 1 Tcf for the forecast period. Cumulative additions during the period 1978

to 2000 for the Mackenzie Delta area and the Beaufort Sea were expected to be 2 and 21 Tcf respectively. Based on a 60:40 gas to oil ratio, Gulf estimated the ultimate potential for natural gas in the Mackenzie Delta-Beaufort Sea area to be 50 Tcf. It predicted cumulative reserves additions during the forecast period of 16.5 Tcf and 17.5 Tcf for the Arctic Islands and East Coast offshore respectively, with corresponding ultimate potentials of 80 Tcf and 71 Tcf.

Home

In considering the ultimate potential of the frontier areas, Home supported, with minor qualifications, the estimates published in EMR Report EP-77-1. Home stated that the gas potential of the Labrador Shelf was probably understated in that report and supported a modest upward revision of the mean estimate of the ultimate potential of this area to about 30 Tcf.

HBOG

HBOG estimated that the established reserves of 5.3 Tcf for the Mackenzie Delta-Beaufort Sea area would grow by an average of 0.7 Tcf per year to reach 22 Tcf by the year 2000. For the Arctic Islands, the discovered reserves of 11.3 Tcf would grow by an average of 1.4 Tcf per year until the year 2000, when reserves would be about 44 Tcf.

As exploration in the frontier areas is in an early stage, HBOG provided a range of ultimate potentials which might be realized, namely, 20 to 55 Tcf for the Mackenzie Delta-Beaufort Sea area, 40 to 90 Tcf for the Arctic Islands and 30 to 90 Tcf for the offshore areas of the East Coast.

Imperial

Imperial stated that the existing reserves in the Mackenzie Delta area of 5.2 Tcf provided threshold requirements for a Dempster lateral, based on current cost estimates. In preparing its forecasts of producibility, Imperial assumed sufficient exploration success to find an additional 15 Tcf of reserves in the Mackenzie Delta-Beaufort Sea area by 1990 and an additional 16 Tcf in the Arctic Islands by the year 2000. Imperial submitted that studies indicated that established island building technology would be feasible and economic to permit development in a significant portion of the Beaufort Sea.

Panarctic

Panarctic estimated that by the end of 1983, there would be an additional 10 Tcf of proved and probable reserves discovered in the Arctic Islands, bringing the total proved and probable reserves to 21.9 Tcf. Panarctic did not show reserves additions beyond 1983 because it felt that 1982 would be a critical point since in that year the Arctic Islands Exploration Group would have fulfilled its commitment to Sun and to Global Arctic Islands Limited. Panarctic considered that investors would be unwilling to spend money in the Arctic beyond 1982 unless approval of a large gas delivery system were imminent.

As a result of an assessment of over 50 known natural gas prospects in the Sverdrup Basin, Panarctic estimated the ultimate potential of the Arctic Islands, occuring in accumulations of over 100 Bcf, to be in the range of 100 Tcf.

PanCanadian

PanCanadian identified two estimates of potential, ultimate and current. The ultimate potential consisted of its estimates of initial proved reserves together with probable and possible reserves additions. The current potential was determined in a similar manner, but because reserves additions could not be estimated with a high degree of certainty, 25 percent and 75 percent discount factors respectively were applied to the probable and possible estimates of reserves additions. PanCanadian stated there was a high degree of probability that the present level of activity would lead to the finding of reserves equivalent to its estimate of current potential.

Based on an in-house evaluation, PanCanadian estimated that at 30 June 1978, for all frontier areas, the proved reserves were 24.3 Tcf, the ultimate potential was 245.3 Tcf and the current potential was 104.5 Tcf.

Polar Gas

Polar Gas estimated that the reserves additions for the Arctic Islands would be in the range of 25 to 42 Tcf during the forecast period. Polar Gas indicated that it was investigating the possibility of transporting the reserves of the Arctic Islands and the Mackenzie Delta-Beaufort Sea area to market through a single transportation system, which could be on-stream by the late 1980's. Polar Gas stated that the total established reserves in these two areas were close to the threshold required to support such a pipeline.

Views of the Board

Estimates of reserves additions and ultimate potential represent the levels of anticipated gas volumes which may be discovered at some future date. These anticipated gas

volumes cannot be considered as reserves now, nor should they be confused with reserves that have already been discovered.

Estimating the rate of reserves additions in the frontier areas must be considered highly speculative at this time, since reserves additions are affected not only by exploratory success but also by economic, regulatory and political decisions.

Accordingly, the Board does not feel justified in publishing independent forecasts. However, it is of the opinion that the submittors' estimates shown in Table 2-11 are representative of a range of volumes that might be attainable within the forecast periods indicated, given the requisite levels of exploration and development. In the case of the East Coast offshore areas, in particular the Labrador Shelf, because of its very hostile environment, some technological advances are undoubtedly necessary before commercial production can be anticipated.

While discoveries of natural gas in Canada's frontier areas have been encouraging and while numerous large structures remain to be drilled, the sizable range of estimates of ultimate potential presented at this inquiry is evidence of the uncertainty which must be attached to the volumes of gas that may be discovered in Canada's frontier areas in the future.

The Board has not undertaken in-depth studies of the ultimate potential of the frontier areas. This is done on a regular and continuing basis by the GSC, by means of a very thorough analysis of relevant data. For purposes of comparison, the GSC estimates published in EMR Report EP 77-1, are shown in Table 2-12 with submittors' estimates.

Deliverability

Views of Submittors

Alberta and Southern

Alberta and Southern assumed a pipeline from the Mackenzie Delta would be completed by 1986. It adopted the NEB deliverability forecast shown on Table 2-20 in the Northern Pipelines Report.

For the Arctic Islands, Alberta and Southern adopted the forecast of Polar Gas.

CPA

CPA assumed that production from the Mackenzie Delta-Beaufort Sea area would commence in 1984 to conform with the Northern Pipelines Report. A production rate of 1 MMcf/d for each 7300 MMcf of reserves was used.

CPA also assumed that production from the Arctic Islands would commence in 1990 at a rate of 1 MMcf/d for each 7300 MMcf of reserves.

The production schedules for the Mackenzie Delta-Beaufort Sea area and the Arctic Islands were based on current reserves for these areas of 16.9 Tcf and did not include production volumes related to reserves additions from future appreciation and new discoveries.

Dome

Dome estimated that the Mackenzie Delta-Beaufort Sea area and the Arctic Islands could be on-stream by 1985 and 1990, respectively, given suitable markets. Its forecasts were based on a rate of take of 1:7300, using initial, connected reserves of 7.3 Tcf for the Mackenzie Delta-Beaufort Sea area and 14.3 Tcf for the Islands. In both areas, Dome projected incremental expansions based on the connection of large volumes approximating 6 Tcf each three years thereafter.

It was also considered that transportation by LNG carrier from both areas was feasible so that earlier deliveries, from lower threshold volumes, were likely to occur.

Gulf

Gulf assumed as a criterion for the Mackenzie Delta-Beaufort Sea area that the Dempster lateral would be completed by 1988. Its deliverability forecast for the area was based on the premise that the line would have an ultimate capacity of 1200 MMcf/d and on evidence given at the Northern Pipelines hearing of an assumed supply of 800 MMcf/d. Gulf indicated that this represented a minimum since the Beaufort Sea had a larger reserves potential than the Delta which could lead to an alternate pipeline route to transport a larger natural gas supply from the whole area. In this regard, Gulf had reference to the formal application filed by Polar Gas to build a pipeline from the Arctic Islands which would have an initial capacity of 2100 MMcf/d and could be increased to 3000 MMcf/d. The company indicated the project could be completed by the mid-1980's.

HBOG

For the Mackenzie Delta-Beaufort Sea area, in its unlimited market case, HBOG assumed that construction of the Dempster lateral would be completed during 1985 and

that production at an initial rate of 712 MMcf/d would commence by the end of 1985. Based on established reserves of 5.3 Tcf and growth at an average of 0.7 Tcf per year, total reserves of 22 Tcf would be reached by 2000. In the limited market case, HBOG did not expect the sale of frontier gas until the late 1990's. Its forecast of deliverability for the limited market case did not identify the frontier source of supply.

For the Arctic Islands, HBOG assumed in its unlimited market case that the Polar Gas pipeline would be completed during 1989 and production would commence by the end of 1989 at an initial rate of 1342 MMcf/d, increasing to 2110 MMcf/d in the second operational year. Based on established reserves of 11.3 Tcf and a yearly reserves growth of 1.4 Tcf, a total of 44 Tcf would be reached by 2000. Arctic Islands deliverability was projected to increase to 4110 MMcf/d in the year 2000.

Imperial

In developing its deliverability forecast for the Mackenzie Delta-Beaufort Sea area, Imperial assumed that production would start in 1987. The company stated that to achieve that timing, a decision would be required by 1982 to proceed with construction of the Dempster pipeline lateral. Imperial's gas producibility forecast was based on current reserves of 5.2 Tcf in the Mackenzie Delta-Beaufort Sea area and reserves additions of 15 Tcf by 1990.

Imperial based its deliverability for the Arctic Islands on the premise of threshold reserves being developed by 1984 and an approval of the proposed 42-inch Polar Gas pipeline by 1986. Production at a rate of 500 Bcf/yr was projected from reserves in the Melville Island area, commencing in 1992. With future discoveries of 16 Tcf by 2000 and the Ellef Ringnes spur line completed, Imperial predicted that total producibility could reach the 1100 Bcf/yr capacity of the Polar Gas pipeline by 1996 and be maintained at that level for the remainder of the forecast period.

Panarctic

Panarctic submitted individual deliverability schedules for all pools in the Arctic Islands, excepting the small accumulations totalling 217 Bcf. The pools for which deliverability forecasts were made contained 11.7 Tcf of proven and probable recoverable pipeline gas.

Forecasts of production were based on two contract limitations, one case assuming that the average daily contract quantity would be 1/6000 of the recoverable pipeline gas reserves and the other assuming that it would be 1/7300 of the reserves. In each case, the maximum daily rate would be 110 percent of the daily contract quantity. It was estimated that current reserves could maintain rates of some 1957 MMcf/d for five years in the first case and 1607 MMcf/d for six years in the second case, before decline occurred. Panarctic did not forecast a probable connection date for Arctic production.

PanCanadian

PanCanadian's forecast of production for the Mackenzie Delta-Beaufort Sea area was based on the assumption that deliveries would commence in 1987. Initial production was predicated on expected "proved" reserves in 1987, and reserves additions thereafter. No estimate of reserves as of 1987 or reserves additions was submitted for the area. The company assumed an initial production rate of 1000 MMcf/d which was maintained for three years. Maximum production of 2500 MMcf/d was forecast to occur by 1996.

For the Arctic Islands, PanCanadian assumed deliveries would commence in 1992 from expected "proved" reserves at that time and reserves additions thereafter. No estimates of expected reserves or reserves additions were submitted. Production from the Arctic Islands was expected to be 2000 MMcf/d initially, reaching 3000 MMcf/d by 1998.

Polar Gas

For the Arctic Islands, based on a 42-inch pipeline system, Polar Gas forecast production to commence in 1985 at 1350 MMcf/d and reaching its base case system capacity of 2100 MMcf/d prior to 1990. The 2100 MMcf/d production rate was maintained to 1995.

For a Delta-Beaufort 30-inch pipeline system, Polar Gas forecast production commencing some time after 1985, reaching system capacity of 1200 MMcf/d by 1990 and maintaining this level until 1995.

Production from the East Coast offshore areas was estimated to commence after 1990 and attain a possible level of 1000 MMcf/d by 1995.

Submittors' deliverability forecasts for the Mackenzie Delta-Beaufort Sea area and the Arctic Islands are shown in Tables 2-14 and 2-15 respectively.

Views of the Board

Having regard to the high degree of uncertainty attached to the various frontier developments at this time, and de-

spite some industry urging to the contrary, the Board is of the opinion that frontier reserves should not be included as a component of available supply for the purposes of this inquiry.

With respect to the Mackenzie Delta, the Board continues to rely on its estimate of deliverability published in the Northern Pipelines Report. It forecast deliveries from the Delta of some 700 MMcf/d based on a rate of take of 1:7300 from the estimated 5.3 Tcf of established reserves. However, until an application has been received by the Board for the construction of a Dempster Lateral and the Board has granted a certificate and is satisfied that the pipeline will be constructed, it does not believe it to be appropriate to include Mackenzie Delta deliverability in the projections of gas availability from established volumes or reserves additions. For purposes of illustration only, the manner in which supply availability would be increased by the addition of the above estimate of Mackenzie Delta deliverability commencing in the latter part of 1987 is shown in Figure 4-1.

No attempt has been made by the Board to develop its own deliverability schedule for the Arctic Islands since there remains great uncertainty as to when gas from this source will be connected to market.

Table 2–14

NATURAL GAS DELIVERABILITY FROM THE MACKENZIE DELTA–BEAUFORT SEA AREA COMPARISON OF FORECASTS
(MMcf/d)

Year	CPA(1)	Dome	Gulf	HBOG	Imperial	PanCanadian	Polar Gas(1)(3)	Alberta and Southern(2)
1984	904	—	—	—	—	—	—	—
1985	904	1000	—	712	—	—	—	—
1986	—	1000	—	822	—	—	—	697
1987	—	1000	—	932	356	1000	—	697
1988	—	1822	400	1041	712	1000	—	697
1989	—	1822	800	1151	712	1000	—	697
1990	904	1822	800	1233	1096	1500	1200	697
1991	—	2644	800	1342	1315	1500	1200	697
1992	—	2644	800	1452	1534	1500	1200	697
1993	—	2644	800	1501	1644	2000	1200	697
1994	—	3466	800	1562	1808	2000	1200	697
1995	732	3364	800	1616	1972	2000	1200	697
1996	—	3277	800	1671	2109	2500	—	697
1997	—	4016	800	1699	2247	2500	—	695
1998	—	3860	800	1753	2246	2500	—	662
1999	—	3723	800	1781	2246	2500	—	642
2000	433	4419	800	1836	2247	2500	—	583

(1)Only data for years shown.
(2)From Northern Pipelines Report Table 2–20.
(3)Production commencing after 1985, reaching capacity as shown.

Table 2–15

NATURAL GAS DELIVERABILITY FROM THE ARCTIC ISLANDS
COMPARISON OF FORECASTS
(MMcf/d)

Year	CPA[1]	Dome	Gulf	HBOG	Imperial	PanCanadian	Polar Gas[1][2]	Prod. Year	Panarctic[3] 1/6000	Panarctic[3] 1/7300
1985	—	—	—	—	—	—	1350	1	1957	1607
1986	—	—	1000	—	—	—	—	2	1957	1607
1987	—	—	2100	—	—	—	—	3	1957	1607
1988	—	—	2100	—	—	—	—	4	1957	1607
1989	—	—	2100	1342	—	—	—	5	1957	1607
1990	1408	1959	2100	2110	—	—	2100	6	1951	1607
1991	—	1959	2100	2767	—	—	2100	7	1901	1604
1992	—	1959	2100	2986	1370	2000	2100	8	1792	1571
1993	—	2781	2100	3205	1480	2000	2100	9	1670	1427
1994	—	2781	2100	3397	1480	2000	2100	10	1569	1438
1995	1408	2781	2100	3589	2849	2500	2100	11	1478	1359
1996	—	3603	2100	3808	3041	2500	—	12	1395	1291
1997	—	3603	2100	3945	3041	2500	—	13	1319	1229
1998	—	3603	2100	4000	3041	3000	—	14	1253	1176
1999	—	4425	2100	4055	3041	3000	—	15	1193	1126
2000	1268	4227	2100	4110	3041	3000	—	16	1102	1081

[a]Only data for years shown.
[b]A&S adopted Polar's forecast.
[c]Panarctic gave no initial year, forecast from year 1 of production. Submitted forecast for 25 years.

Chapter 3
Natural Gas Requirements

EXISTING MARKETS

Introduction

In assessing Canada's natural gas supply and demand prospects, the Board must prepare forecasts of reasonably foreseeable Canadian requirements. This chapter of the report is a summary of the evidence and views on the requirements for natural gas to satisfy domestic demand in those areas currently served by gas and of the potential for natural gas to penetrate energy markets beyond existing transmission systems.

To assist it in making its determination of demand for natural gas, the Board requested that all interested parties provide forecasts, comments and opinions on various aspects of energy demand. Submittors were encouraged to present estimates of natural gas demand in the context of a forecast of total energy demand. Those using such an approach were requested to provide a breakdown of demand by energy type and to make explicit their assumptions with respect to such variables as economic growth, population growth, energy prices and market shares. Submittors were also requested to provide forecasts of the Canadian demand for gas in market areas presently served by existing transmission facilities for each calendar year, 1978 to 2000, on the basis of various price relationships at Toronto of the city-gate price of gas to the refinery-gate price of crude oil.

Twenty-nine submittors provided energy demand forecasts. This represents approximately three times the number of submissions received for the Canadian oil supply and requirements inquiry held earlier in 1978. Many of the submissions provided valuable insight into the Canadian demand for natural gas. The Board has taken this evidence into consideration in preparing its estimates of the Canadian demand for gas.

The Board used a total energy approach in arriving at its own forecast of natural gas demand. Demand for natural gas in existing market areas is projected to grow at an average annual rate of approximately 2.9 percent to reach 2069 Bcf/year in 1985, 2286 Bcf/year in 1990 and 3092 Bcf/year in the 2000. These amounts represent approximately 18 percent of total primary energy demand.

METHODOLOGY AND ASSUMPTIONS

Methodology

Views of the Submittors

The demand forecasts provided by submittors fell into four categories: projections of total energy demand for all of Canada; projections of total energy demand for a particular region or province; natural gas demand forecasts for all of Canada; and finally, natural gas demand forecasts for a particular region, province or service area. Several of the submissions contained natural gas expansion scenarios that included volumes for one or more of the potential new market areas such as on Vancouver Island, in the Province of Quebec and the Maritimes.

Several submittors based their forecasts on studies that were specifically prepared for either this inquiry or the Board's earlier 1978 oil inquiry. Some relied upon other submittors' forecasts or used the forecasts contained in the Northern Pipelines Report or AERCB Report 78-E which deals with Alberta's demand for natural gas.

Only a limited number of the submissions presented specific demographic, economic, energy price and interfuel competition assumptions or projections. However, most submittors did provide details of demand by sector, and some of them also, by fuel type.

Six submittors forecast total energy demand for all of Canada. Of these submittors, Alberta and Southern, Gulf, Imperial, ProGas and Shell prepared primary energy demand forecasts while Polar Gas prepared a secondary energy demand forecast. Generally, these forecasts were based upon population and economic projections for each of the provinces within the context of a forecast of economic and demographic variables for the country as a whole. The forecasts included allowances for future improvements in energy efficiency.

The forecast methodologies of the remaining 23 submittors included projections of historical trends (with and without adjustments for conservation and increased fuel efficiency) and the use of econometric models. In some instances federal or provincial forecasts were adopted.

Views of the Board

Since publication of its Northern Pipelines Report, considerable work has been carried out by the Board to improve its forecasting methodology in each market sector. This work involved the re-specification and re-estimation of many of the equations. These changes have been incorporated into the Board's present total energy forecasting system* and were used in developing its current estimates of domestic demand. This system was also employed in preparing the forecast presented in the Board's 1978 Oil Report.

Given the uncertainties in predicting economic growth and future energy price levels, the Board evaluates a number of energy demand scenarios. Nonetheless, detailed presentation of the results is generally restricted to only one demand forecast, referred to as the "base case". A brief discussion of the "high demand" and "low demand" cases is presented in a later section of this chapter. A comparison of the corresponding economic projections is contained in Appendix 3-A.

For practical considerations only, the base case is presented in detail; however, it should be stressed that the Board does not intend to convey the impression that the high demand and low demand scenarios are unrealistic projections of future energy demand. Consideration must be given to a range of possibilities in order to recognize the complexities and uncertainties inherent in forecasting long-term energy demand.

Demography and Economic Growth

Views of the Submittors

The general consensus among those submittors who prepared energy demand forecasts for all of Canada was that economic growth would decrease gradually and that population would increase at a very slow rate over the forecast period. Several submittors supplied economic and demographic projections on a regional, provincial or national basis. Those projections of economic growth that were made on a national basis are summarized in Table 3-1.

All of the national forecasts reflected the basic assumption that the real GNP growth rate will gradually decline. The lower rates of economic growth were attributed in large part to population, household formation, labour force and productivity assumptions.

Of the remaining submittors who prepared natural gas demand forecasts or energy demand forecasts on a regional or provincial basis, several specified the economic and demographic factors assumed in their analyses. Most concurred with the view that the economy would grow at a decreasing rate over the forecast period. Some of these submittors, however, forecast that certain provincial economies would grow at a constant or at an increasing rate over part or all of the forecast period.

Table 3-1

REAL GROSS NATIONAL PRODUCT GROWTH RATES
Comparison of Forecasts
(Percent per Annum)

	1977-80	1980-85	1985-90	1990-95	1995-2000
AERCB	4.1	4.5	3.7	3.7	3.7
Gulf	4.7(1)	4.1	3.4	3.2	3.0
Imperial	4.4	4.4	3.5	3.5	3.3
Polar Gas	4.5	4.0	3.5	3.0	2.8
ProGas	3.7	3.6	3.3	3.1	2.9
Shell	4.7	3.9	3.3	3.0	3.0
TransCanada	4.0(2)	4.1	3.6	3.4	3.3
NEB	4.6	4.5	3.7	3.4	3.0
Actual Period of Forecast					

(1) 1975 to 1980
(2) 1978 to 1980

* The Board's present forecasting system is described in more detail in papers which were presented to the Canadian Energy Policy Modelling Conference on May 19-20, 1978 in Vancouver, entitled: "The Energy Demand Forecasting System of the National Energy Board" and "A Model for Forecasting Passenger Car Gasoline Demand in Canada".

Views of the Board

The Board's projections of the Canadian economy, including the population projections, were prepared using the Board's version of the CANDIDE 1.2M econometric model of the economy in conjunction with selected assumptions on government fiscal and monetary policies and exchange rates. These projections were prepared in March 1978 and were discussed in Chapter 3 of the Board's 1978 Oil Report. These have been reviewed in the light of the evidence and have been adopted for the present forecast.

The Board's base case economic forecast, as set out in Appendix 3-A, projects fairly strong growth through the 1978 to 1985 period. Reductions in population growth, relative to historical experience, and expected reductions in the growth of productivity result in a significant decline in real growth in the economy after 1985.

On the demographic side, the annual rate of increase in population is predicted to slow down gradually in the forecast period from an average of 1.6 percent over the historical period 1960 to 1976, to 1.0 percent over the 1986 to 2000 period. This assumes that the fertility rate will gradually decline from a 1977 level of 2.1 children per female of child-bearing age to slightly less than 2 children by the year 1980, and that the rate stabilizes thereafter. Net immigration in each year of the forecast period is assumed to be 100,000 persons. The resultant population in 2000 is forecast, in the base case, to be 29.8 million.

Other features characterizing the projection of the economy in the base case and a discussion of the high case are provided in Appendix 3-A.

Energy Prices and Interfuel Competition

Views of Submittors

Price not only influences the overall level of demand for energy, but the relative prices of the various energy sources also indicate the degree of interfuel competition, and are important determinants of the market shares captured by the various competing energy sources.

The majority of submittors who specified pricing relationhsips for natural gas and crude oil assumed that, compared on a basis of thermal content, the Toronto city-gate price of natural gas would remain at a price equivalent to 85 percent of the crude oil price at the refinery-gate, or would increase slightly but remain below the equivalent price of crude oil. In contrast, IPAC and Gulf assumed that gas prices would reach parity with the price of crude oil sometime during the forecast period.

Most submittors who discussed the subject assumed that electricity rates would increase in real terms over the forecast period and remain well above oil and gas prices on a basis of thermal equivalence. Nova Scotia expected that with improved technology, the relative costs of home heating by oil and electricity would begin to converge after 1982 and electricity would become cost competitive by 1985 to 1986.

Few of the submittors provided energy market share projections by sector. Of those that did, the general expectation was that the share of the residential market held by natural gas would increase moderately, as would the market share held by electricity. The share of the residential market held by oil would decline in proportion to the gains made by natural gas and electricity.

In the commercial sector, it was generally forecast that gas would maintain its present market share or grow very slightly over the forecast period. Most submittors who provided market share projections expected moderate growth over the forecast period for electricity at the expense of oil. Shell, however, expected that market shares of all fuel types would remain stable in the commercial sector.

In the industrial sector a moderate increase in the market share for natural gas was projected over the forecast period. Electricity was also projected to increase its market share, but to a lesser extent than natural gas. Coal's market share was projected to decrease in proportion to the gains made by natural gas and electricity.

Views of the Board

In the longer term, the international price of crude oil will be a major factor determining domestic crude oil prices which, in turn, influence domestic natural gas prices. Because of the uncertainties inherent in future energy price levels, the Board forecasts energy demand under different price assumptions.

As in the 1978 Oil Report, for its no gas-expansion base case forecast the Board assumes that the world price of crude oil will remain constant in real terms at its 1977 level and that the domestic price of crude oil will rise towards the world price, approaching it by the end of 1981. It is also assumed that the city-gate price of natural gas in Toronto will increase with the price of domestic crude and, maintain the present price relationship of approxi-

mately 85 percent of that for crude oil on a thermal basis.

Energy prices at the burner-tip are calculated using Toronto as the reference point. It is assumed that distribution margins for petroleum products and natural gas will remain constant in real terms. Electricity prices are assumed to increase in real terms until 1981. As a consequence of these assumptions, the burner-tip price of each fuel is forecast to remain constant in real terms after 1981.

Different price assumptions are made for the high and low energy demand cases. In the high demand case it is assumed that the world price of crude oil will decrease in real terms by approximately 5 percent per annum, while in the low demand case it is assumed that the real price will increase by about 5 percent per annum. These assumptions are analogous to postulating that the burner-tip energy prices will decrease or increase in real terms relative to the base case by approximately 4 percent per year, throughout the forecast period. This is assumed to be the case for each region, market sector and energy type. The resulting range of energy demand is presented and discussed in the next section.

With respect to interfuel competition, the assumptions just outlined regarding energy prices are used in conjunction with other factors in developing the market shares that are incorporated into the Board's forecast. These market shares are developed on a judgmental basis after considering the evidence and having regard to the Board's own knowledge on relative energy prices, relative capital costs of installing heating equipment, and historical and current trends.

For Canada as a whole the Board anticipates that natural gas, and electricity in particular, will increase their market shares at the expense of petroleum products in the residential sector. For the commercial sector the market share for gas is expected to drop slightly, but as in the residential sector, the share held by electricity is expected to increase significantly. For the industrial sector, both gas and electricity are projected to increase their shares slightly. It should be noted, however, that, for all sectors, the market share behaviour varies considerably between regions, reflecting differences in market conditions, expected relative prices and the availability of other fuels. As noted above, these market shares represent the Board's base case projections and do not include additional gas volumes or changes in market shares as a result of the extension of service into new market areas.

Forecast of Total Energy Demand

Forecasts of Submittors

Six submittors – Alberta and Southern, Gulf, Imperial, Polar Gas, ProGas and Shell – provided long-range primary energy demand forecasts. As shown in Table 3-2, all of these forecasts indicated that primary energy demand would almost double between now and the year 2000. The table also indicates that the forecasts varied particularly towards the end of the forecast period.

Some of the submittors who prepared total energy demand forecasts did not follow the Board's previously established treatment of primary and secondary energy. This fact accounts for the greatest discrepancy among the forecasts detailed in Table 3-2. In its 1977 and 1978 Oil Reports, the Board outlined its definitions and treatment of primary and secondary energy demand. It noted that roughly three units of primary energy, in the form of fossil fuels, are necessary to generate one unit of secondary energy in the form of electricity. The Board's treatment of primary energy assumes that the ratio between primary and secondary hydro and nuclear generated electricity is the same as that for electricity generated from fossil fuels. This assumption facilitates the study of long-term trends in primary energy demand by freeing the analysis from possible changes in electricity generation patterns between the use of either fossil fuels or nuclear and hydro power.

In determining primary energy demand Gulf did not convert its forecast of demand for nuclear and hydro electricity on the basis of the fossil fuel input which would be required to generate the same amount of electricity. If the Board's approach were applied to Gulf's primary energy demand forecast, the resultant figures would be approximately 8 quads for 1975 and 16 quads for the year 2000. It is evident that the adjustment substantially narrows the range of the primary energy demand forecasts summarized in Table 3-2.

Table 3-3 provides a comparison of the primary energy demand growth rates for Canada as forecast by the above-mentioned submittors and also presents the Board's assessment. Over the forecast period, the average annual rate of growth of primary energy demand was forecast by submittors to range from 2.4 to 3.1 percent.

Most forecasts indicated a decrease in the rate of growth of energy demand over the forecast period. The submit-

Table 3–2

PRIMARY ENERGY DEMAND – CANADA
Comparison of Forecasts
(Trillions of Btu's)

	1978	1980	1985	1990	1995	2000
A & S	8485	8950	10225	11682	13346	15248
Gulf	6365(1)	—	—	—	—	11869
Imperial	8500	—	11000	—	—	16700
Polar Gas	8840	9426	10784	12451	14259	—
ProGas	8323(2)	9331	10993	12698	14619	16670
Shell	8390(2)	9168	10439	11535	12790	14082
NEB	8948	9576	11000	12644	14454	17074

Actual Year
(1) 1975
(2) 1977

Table 3–3

PRIMARY ENERGY DEMAND GROWTH RATES – CANADA
Comparison of Forecasts
(Percent Per Annum)

	1978–1980	1980–1985	1985–1990	1990–1995	1995–2000	1978–2000
A & S	2.7	2.7	2.7	2.7	2.7	2.7
Gulf	3.5(1)	2.7	2.5	2.0	2.0	2.5(2)
Imperial	3.8	3.8	2.8	2.8	2.8	3.1
Polar Gas	3.3	2.7	2.9	2.7	-	2.9(3)
ProGas	3.9(4)	3.3	2.9	2.9	2.7	3.1(5)
Shell	3.0(4)	2.6	2.0	2.1	1.9	2.4
NEB	3.4	2.8	2.6	3.0	3.4	3.0

Actual Period of Forecast
(1) 1975 – 1980
(2) 1975 – 2000
(3) 1978 – 1995
(4) 1977 – 1980
(5) 1977 – 2000

tors generally projected that the rate of growth over the forecast period would be less than that for the second half of this decade. The only exception was Alberta and Southern who forecast a constant growth rate over the entire period.

Forecast of the Board

The term of the Board's forecast now extends to the year 2000, an additional five years from the period of the forecast presented in the 1978 Oil Report. To facilitate presentation of the extensive material involved, the main text of this chapter highlights the Board's forecast for the year 1990. This time frame of a little more than ten years is short enough to ensure a reasonable degree of dependability of forecasting and yet long enough to allow for the lead-time required by major energy developments affecting energy trends.

The Board's forecast of energy demand is based on the same assumptions with regard to economic/demographic activity and energy prices as those presented in the Board's 1978 Oil Report. The present forecast incorporates only minor changes resulting from more recent energy consumption data and the additional evidence of this inquiry.

Table 3–4

PRIMARY ENERGY DEMAND – CANADA
NEB Forecast
(Trillions of Btu's)

	1978	1980	1985	1990	1995	2000
Oil	3,793	3,948	4,272	4,507	4,818	5,315
Natural Gas	1,644	1,764	2,069	2,286	2,642	3,092
Ethane & LPG's	88	109	142	164	169	173
Coal	772	874	956	1,106	1,232	1,483
Hydro & Nuclear(1)	2,570	2,788	3,431	4,342	5,220	6,462
Renewable Energy(2)	81	93	130	239	373	549
Total Primary Energy	8,948	9,576	11,000	12,644	14,454	17,074

(1)Expressed on a fuel equivalent basis assuming 10,000 Btu's per Kwh
(2)Includes solar and hog fuel.

A change of a conceptual nature is also introduced. Hog fuel consumption (i.e. the use of wood waste as fuel) is now included in the Board's forecast. Previously, lack of sufficiently reliable historical data had prevented the Board from including the use of wood in its total energy demand forecasts, although such use had been examined as it related to the possible future displacement of other energy forms.

The overall result of the above changes is such that the new forecast of energy demand is approximately 1.4 percent higher for the year 1995, which was the last year of the Board's projection in the 1978 Oil Report. The Board's forecast of primary energy demand is summarized in Table 3-4 and illustrated in Figure 3-1. The forecast implies an average annual growth rate of approximately 3 percent for total energy demand over the forecast period.

The Board's projections of total primary energy for the high and low demand scenarios are compared to its base case forecast in Table 3-5 and Figure 3-2. The numbers provide a general insight into the sensitivity of the energy demand forecast to the major underlying assumptions. For example, according to the Board's estimates for the year 1990, total primary energy demand in Canada could be 21 percent higher or 13 percent lower than the base case forecast, depending on conditions affecting the major determinants of that demand.

Table 3–5

PRIMARY ENERGY DEMAND – CANADA
Range of NEB Scenarios
(Quads)

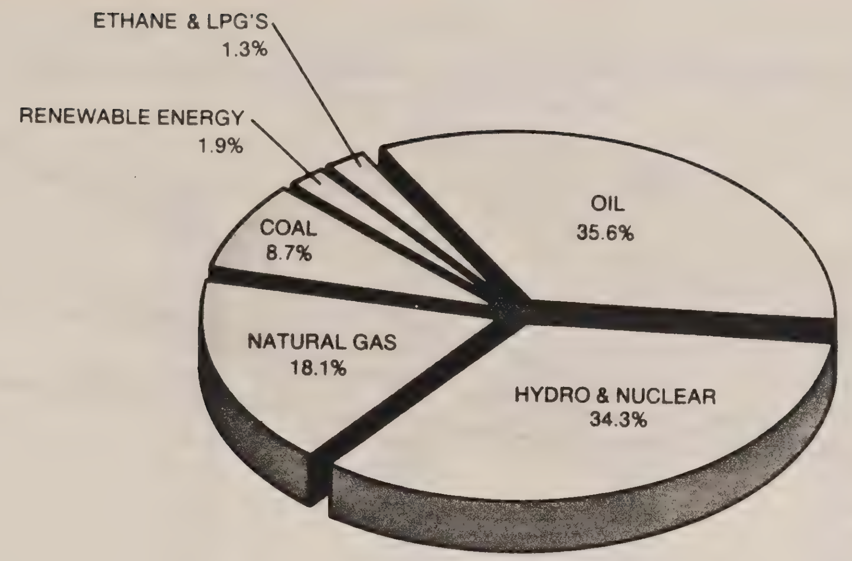
	1985	1990	2000
High Demand Case	12.1	15.2	25.1
Base Case	11.0	12.6	17.1
Low Demand Case	10.3	11.0	13.1

Forecast of Natural Gas Demand

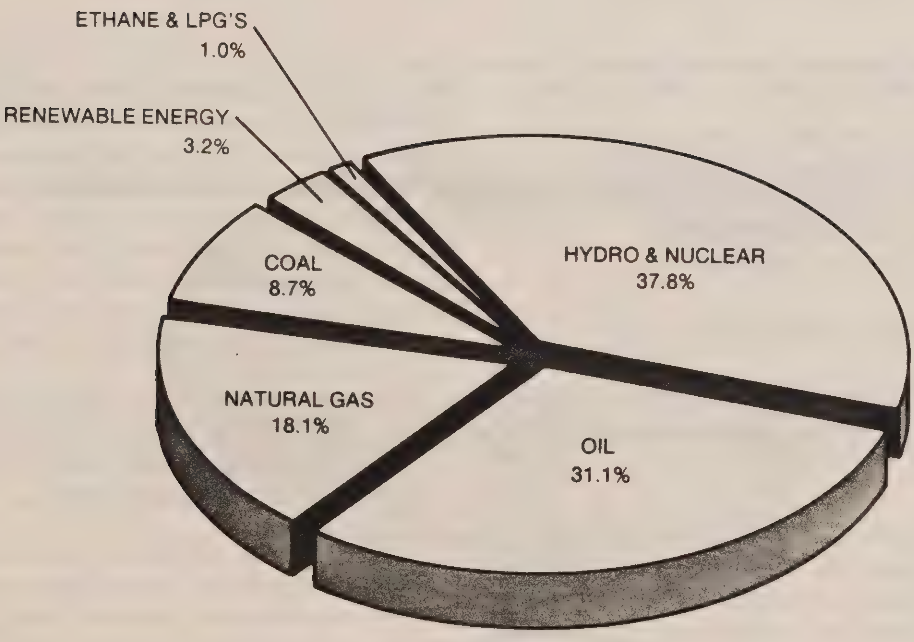
Forecasts of Submittors

Although the Board received a broad range of natural gas demand forecasts, in general, there appears to be a consensus that demand will not grow quite as rapidly as previously expected. Estimates of total net sales of natural gas provided by the various submittors are presented in Table 3-6. Of these, Home submitted the highest estimate (2489 Bcf) and TransCanada provided the lowest estimate (2030 Bcf) for 1990. The difference of 459 Bcf was due in large part to the variations in the underlying assumptions and forecasting methodologies.

The submittors' forecasts implied average annual growth rates in demand for natural gas to the year 2000 ranging from a low of 2 percent as submitted by Norcen to a high



1990
12,644 TRILLIONS OF BTU'S



2000
17,074 TRILLIONS OF BTU'S

Figure 3-1 **PRIMARY ENERGY DEMAND – CANADA**
NEB Forecast

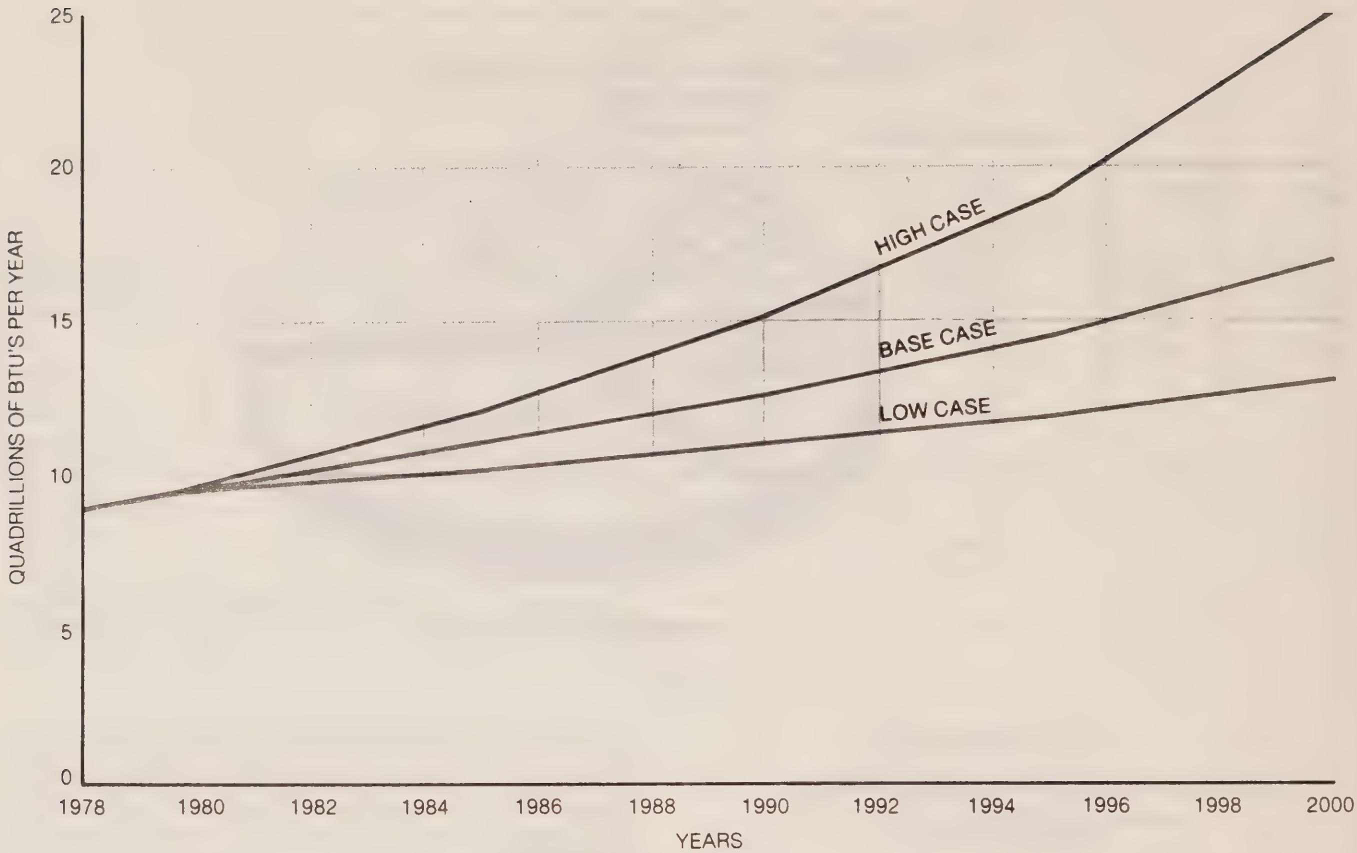


Figure 3-2 **RANGE OF PRIMARY ENERGY DEMAND — SCENARIOS NEB Forecast**

of 3.4 percent as provided by Gulf. Table 3-7 summarizes the growth rates for natural gas requirements for the various submittors.

Several of the submittors forecast natural gas requirements on a provincial and on a sectoral basis. These estimates are contained in Appendix 3-B and are discussed in the following sections. In making comparisons among the various sectoral estimates of the submittors, it should be noted that a number of definitional differences exist which serve to make appropriate comparisons more difficult. An attempt has been made to identify these differences.

Residential Sector

Most of the submittors' forecasts for the residential sector indicated that the demand for natural gas would increase from approximately 325-360 Bcf in 1978 to 450-490 Bcf in 1990 and to 525-570 Bcf in 2000. This represented an average annual growth rate of 2.2 percent within the range over the forecast period.

While several submittors presented forecasts which lay outside this range, the evidence indicated several reasons for the divergence. Imperial's forecast assumed considerable substitution of natural gas for oil products. Shell's forecast of gas requirements in the residential sector included natural gas use in all apartment buildings, while most forecasts included such consumption in the commercial sector.

Most submittors forecast that the market share of natural gas in the residential sector in Canada would increase moderately to the year 2000, since it was felt that natural gas would continue to be favoured over oil in the residential market and that conversions to gas would continue. It

Table 3–6

TOTAL NET SALES OF NATURAL GAS – CANADA (EXISTING MARKETS)
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	1576	1703	2025	2278	2875
A & S	1499	1619	1850	2113	2759
Dome	1491	1599	1856	2095	2626
Gulf	1495	1646	2016	2413	3113
Home	1790	1957	2260	2489	2942
Imperial	1498	1602	2029	2370	2934
IPAC	1523	1673	1973	2218	2734
Norcen	1552	1673	1883	2058	2422
PanCanadian	1680	1861	2129	2371	2921
Polar Gas	1494	1621	1920	2268	2972
ProGas	1515	1633	1841	2076	2482
Shell	1493	1590	1869	2099	2558
TransCanada	1514	1605	1802	2030	2563
NEB	1506	1620	1912	2134	2893

was generally assumed that natural gas would maintain its competitive advantage in the Prairies and British Columbia, allowing increased penetration of markets. In Ontario and Quebec, Gulf expected the preference for natural gas to continue, despite its assumption that natural gas prices would reach equivalence with competing fuels on a thermal basis. It attributed this conclusion to the convenient, clean-burning characteristics of gas and the relatively low installation/conversion costs involved.

Several submittors expected that energy demand, and in turn the demand for natural gas would grow more slowly than in the past as a result of lower growth rates in household formation, a continuing shift towards less energy intensive housing and the impact of conservation measures.

Commercial Sector

Most of the submittors indicated that this demand for natural gas would increase from approximately 305-335 Bcf in 1978 to 465-505 Bcf in 1990 and 515-630 Bcf in 2000. This represented an average annual growth rate of 2.7 percent within the range over the forecast period.

There are several reasons why some of the submittors' forecasts lay outside this range. As mentioned in the preceding section, Shell's forecast for gas requirements in the commercial sector excluded natural gas use in all apartment buildings as this was included in the residential sector requirements. Imperial's forecast assumed considerable substitution of natural gas for oil products.

Table 3–7

TOTAL NET SALES OF NATURAL GAS GROWTH RATES – CANADA (EXISTING MARKETS)
Comparison of Forecasts
(percent per annum)

	1978–1990	1990–2000	1978–2000
AGTL	3.1	2.4	2.8
A & S	2.9	2.7	2.8
Dome	2.9	2.3	2.6
Gulf	4.1	2.6	3.4
Home	2.8	1.7	2.3
Imperial	3.9	2.2	3.1
IPAC	3.2	2.1	2.7
Norcen	2.4	1.6	2.0
PanCanadian	2.9	2.1	2.5
Polar Gas	3.5	2.7	3.2
ProGas	2.7	1.8	2.3
Shell	2.9	2.0	2.5
TransCanada	2.5	2.4	2.4
NEB	2.9	3.1	3.0

Most submittors forecast that the market share for natural gas in the commercial sector in Canada would remain rel-

atively constant or would increase slightly over the forecast period. Several submittors expected that natural gas would maintain a price advantage over oil and electricity in the commercial markets of most regions. Gulf believed that natural gas sales would capture both incremental demand and conversions by existing petroleum users in existing market areas.

New building codes and federal government programs to save energy were expected to reduce the rate of growth of energy consumption including natural gas sales in this sector. Polar Gas noted that conservation in the commercial sector was likely to be confined mainly to new buildings.

Industrial Sector

The Board received a broad range of forecasts of natural gas requirements in the industrial sector. For the year 1990, this range was from 789 Tcf to 1173 Tcf. The average annual growth rates for this sector varied from 2.5 percent to 4.0 percent over the forecast period.

Several major underlying factors accounted for the variability in the forecasts. Definitional inconsistency among the submittors was common for this sector. Estimates of natural gas requirements in the industrial sector included various combinations of energy use requirements, petrochemical requirements and requirements for industrial thermal generation.

Most submittors noted that demand for natural gas in the industrial sector in Ontario and Quebec would depend primarily on the supply of heavy fuel oil to those markets. It was expected that heavy fuel oil would be sold at whatever price was necessary to clear the market, since it is a joint product of the refining of crude oil to meet the demand for lighter products. Consequently, the forecast growth rates of the demand for natural gas were lower than they otherwise might have been. In contrast, most submittors expected that in western Canadian industrial markets, natural gas would continue to maintain its dominant position based on price and availability.

Thermal Electric Sector

A definitional inconsistency among the submittors was prevalent for this sector. While some estimates included only the requirements of the utilities for natural gas to generate electricity, other forecasts included such usage by the industrial sector. As a result, estimates for 1990 were in the order of either 50 Bcf or 150 Bcf.

In general, submittors indicated that natural gas sales to utilities for the generation of electricity would grow slowly in some regions and decline in others over the forecast period, whereas natural gas sales for industrial self-generation of electricity would increase moderately. As a result, most submittors believed that total natural gas requirements for electricity generation would either increase quite slowly to the year 2000 or decrease somewhat.

Petrochemical Sector

Forecasts of natural gas requirements in the petrochemical sector ranged from 110 Bcf to 277 Bcf in 1990 although most estimates fell within the 200-277 Bcf range.

Submittors' forecasts varied due to inclusion or exclusion of ethane in natural gas demand, the number of plants assumed to come on stream and the estimated feedstock and fuel requirement per plant. Imperial and Dome, for example, excluded ethane from their forecasts while Gulf included it in its forecast.

Most submittors expressed the view that natural gas demand in the petrochemical sector would exhibit rapid growth, particularly over the early part of the forecast period. Submittors agreed that any new world-scale petrochemical plant using natural gas as a feedstock brought on stream prior to the year 2000 would be located in Alberta.

Many submittors provided forecasts to the Board based upon recently published estimates by AERCB and NEB. Some submittors carried out their own analysis by taking into account estimates of projected start-up dates for new primary petrochemical plants, requirements for the new plant capacity and possible sources of raw material feedstocks.

Forecast of the Board

Overview

The Board expects that the growth in demand for natural gas in existing market areas will slacken during the first half of the forecast period as a result of increasing energy real prices until 1981, lower growth in the economy and the effects of various energy conservation measures. During the second half of the forecast period, growth in demand is expected to increase, partly as a result of the fact that higher real energy prices and other conservation measures are assumed to have had most of their impact by about 1990.

Total net sales are projected to increase from 1506 Bcf in 1978 to 2134 Bcf in 1990 and 2893 Bcf in 2000. As indicated by the data presented in the section on primary energy (See Table 3-4), the total demand for natural gas is projected to grow at an average annual rate of approximately 2.9 percent over the forecast period. Natural gas is expected to satisfy approximately 18 percent of total primary energy demand. This represents little change from the Board's previous forecast of total gas demand as provided in its 1978 Oil Report.

The current forecast of total net sales of natural gas in Canada for the year 1990 is 3.8 percent higher than that prepared for the 1978 Oil Report, and 11.4 percent lower than the forecast that was used for the Northern Pipelines Report. The differences are discussed briefly by market sector in the following sections.

In addition to developing a base case of natural gas demand, the Board also developed high and low demand cases. The general rationale and description of these scenarios were provided earlier in this report in the discussion of total energy demand and the related assumptions regarding demographic/economic growth and energy prices. A summary of the results is provided in Table 3-8 and Figure 3-3.

Table 3–8

NET SALES OF NATURAL GAS – CANADA (EXISTING MARKETS)

Range of NEB Scenarios

(Bcf/Year)

	1985	1990	2000
High Demand Case	2049	2542	4335
Base Case	1912	2134	2893
Low Demand Case	1746	1845	2161

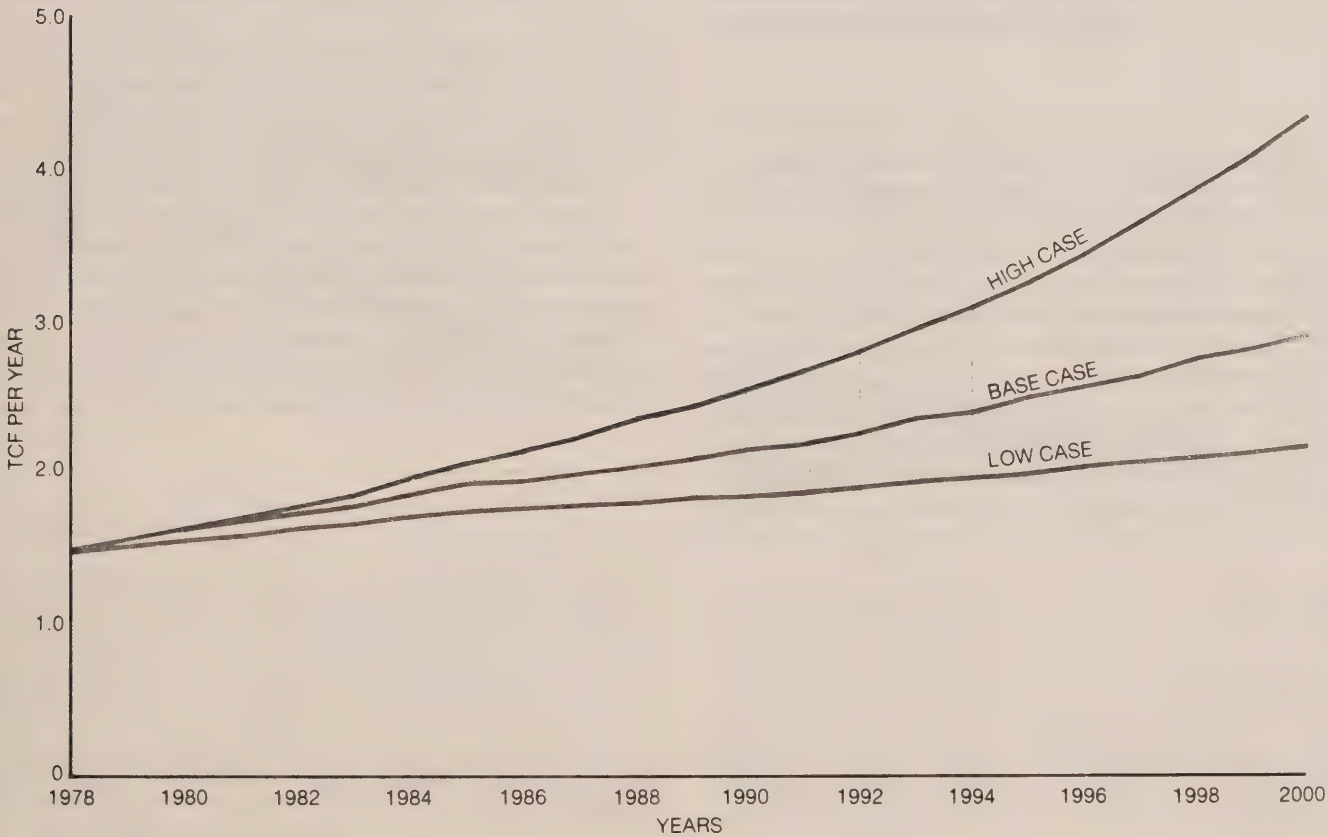


Figure 3-3 **NET SALES OF NATURAL GAS — CANADA (EXISTING MARKETS)**
Range of Scenarios NEB Forecast

According to the Board's projections, total net sales of natural gas in existing market areas could be about 19 percent higher or 14 percent lower than the Board's base case in 1990, depending upon the assumptions made regarding the major determinants of energy demand.

In addition, Figure 3-4 serves to compare the Board's projection of total net sales with the high and low range of the submittors' forecasts. It should be noted that neither the high nor the low forecast is necessarily comprised of the figures of any one submittor, but rather is composed of the highest, or lowest, value submitted for each year of the forecast period. Forecasts that were not entirely independent, but were based largely on previously published forecasts of the Board, were excluded from this comparison.

For purposes of comparison with the forecasts of the submittors, the Board's forecast is also presented in Appendix 3-B.

With respect to natural gas demand within the various market sectors, the Board's base case forecast of net sales is presented by province and market sector in Appendix 3-C.

Residential Sector

The demand for natural gas in the residential sector in existing market areas is expected to increase from 338 Bcf in 1978 to 440 Bcf in 1990 and 545 Bcf in 2000 with an average increase over the whole forecast period of 2.2 percent per annum. The projected growth rate represents a marked slowdown from the 1960's when rapid penetration of the Ontario and British Columbia markets was occuring. Over the 1970 to 1977 period, growth in the demand for natural gas in the residential sector dropped to an average 3.2 percent per year from 8.5 percent over the 1960 to 1970 period. This decline in the growth rate is consistent with slower market penetration, slower growth in population and economic activity, as well as rapid es-

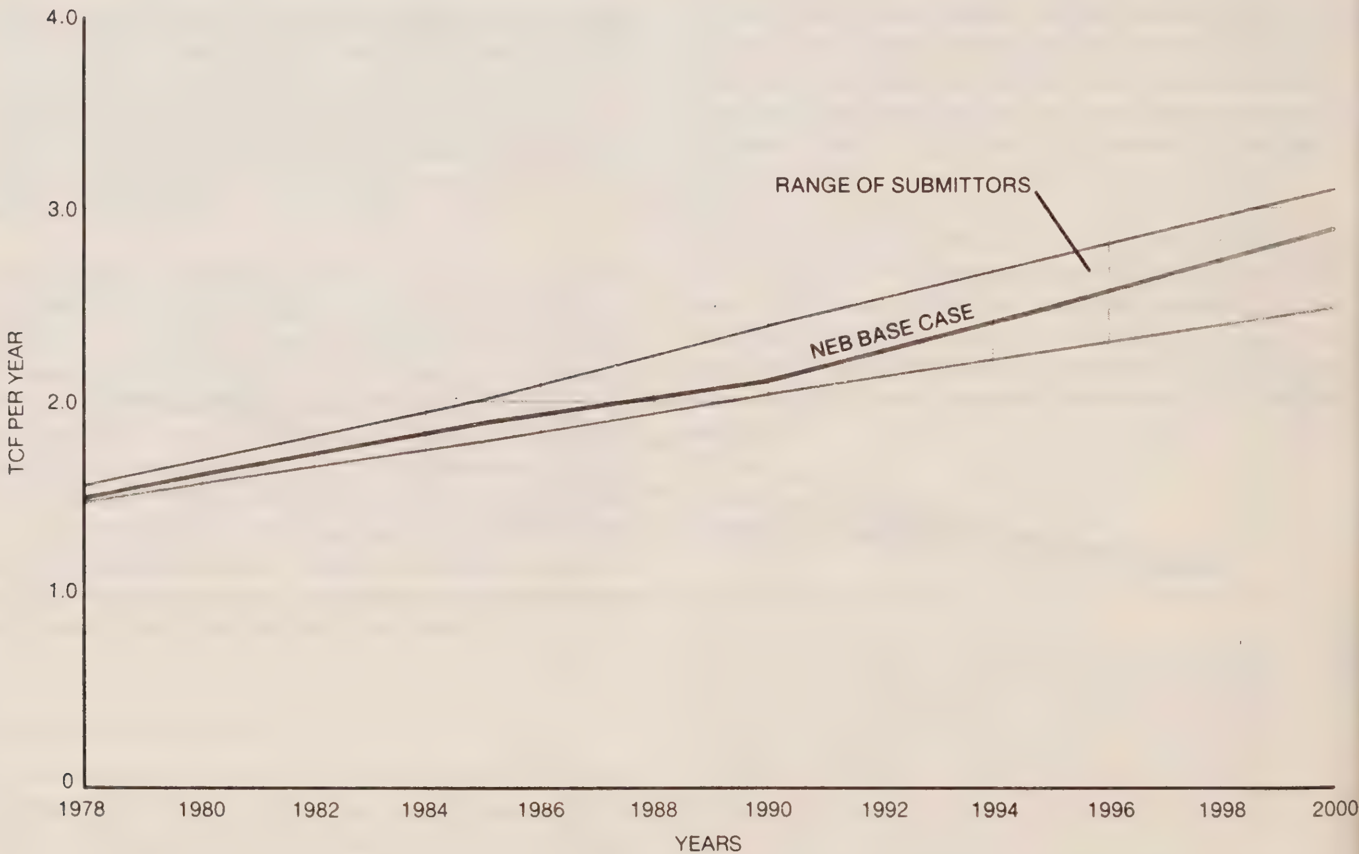


Figure 3-4 **NET SALES OF NATURAL GAS – CANADA (EXISTING MARKETS) Comparison of Forecasts**

calation of energy prices. Growth over the forecast period is expected to slow moderately compared to growth in the 1970 to 1977 period, mainly as a result of a further response to higher energy prices and other conservation effects, as well as a slowing in the rate of penetration of residential markets. Over the forecast period the share of natural gas in the residential market is expected to increase marginally from 29.0 percent in 1978 to 32.3 in 2000.

Growth rates in the residential demand for natural gas on a regional basis do not vary significantly. In Quebec, in this case, minimal additional penetration of natural gas is expected, given the current pricing situation. In Ontario and British Columbia, demand is expected to grow slightly faster than the average, since gas penetration of these markets is expected to continue over the medium term, given the relatively favourable price outlook for natural gas in this sector as compared to alternatives, and other desirable characteristics of natural gas. In the Prairies, natural gas is expected to maintain its significant competitive advantage, although it is anticipated that saturation of these markets will preclude further major increases in the market share held by natural gas.

On a total Canada basis, the forecast demand for natural gas in the residential sector is very similar to the corresponding gas demand forecasts prepared for the Board's 1978 Oil Report and for its Northern Pipelines Report. The current forecast is 3.6 percent and 3.2 percent higher in 1980 than these previous two forecasts, respectively, and 5.6 percent and 3.0 percent lower in 1995. These differences occur mainly as a result of additional historical data and of the evaluation of the evidence. Further analysis also indicated that the conservation effect in the residential sector should be somewhat greater than previously assumed and this has been incorporated in the present forecast.

Commercial Sector

The Board estimates natural gas requirements in the commercial sector will increase from 336.3 Bcf in 1978 to 499 Bcf in 1990 and to 632 Bcf in year 2000 representing an average annual rate of growth of 2.9 percent for the forecast period. This rate is a fraction of the growth of 13.2 percent observed during 1960-1973, a period characterized by low energy and natural gas prices and increasing penetration by gas in Ontario and western Canada. The forecast rate of growth is also much lower than the rate of 5.3 percent observed during 1973-1977, a period marked by higher energy and gas prices and by the approaching of market saturation in terms of gas use. The estimated growth rate for the period 1978-2000 reflects relatively lower projected economic growth, higher conservation in response to higher energy prices and a tapering of growth in gas demand due to saturation. The market share of natural gas is estimated to remain stable at about 40 percent during 1978-1990, after which it is projected to decline to 36.5 percent by the year 2000.

A comparison of the current forecast of natural gas demand in the commercial sector with previous forecasts indicates that the present forecast is higher by 8.9 percent in 1980 and by 5.4 percent in 1990 than the natural gas demand forecast in the 1978 Oil Report. At the same time it is lower by 3.0 percent in 1980 and by 7.9 percent in 1990 than the demand forecast in the Northern Pipelines Report.

The difference between the current forecast and 1978 Oil Report forecast is explained by adjustments to estimates of total energy demand in the commercial sector in the light of the latest available statistics and of the evidence presented at the hearing. In the Northern Pipelines Report higher economic growth and lower conservation was forecast than in the present report, resulting in higher energy and natural gas demand estimates.

Industrial Sector

The Board forecasts that the demand for natural gas in the industrial sector of Canada will increase from 548 Bcf in 1978 to 815 Bcf in 1990 and 1308 Bcf in 2000 with an average annual growth rate over the forecast period of 4 percent. In contrast, industrial gas demand increased at an average annual rate of 10.4 percent between 1960 and 1976. Gas demand in the future is expected to grow significantly less rapidly than in the past because of a lower rate of growth in industrial economic activity and because of higher gas prices, both in absolute terms and also relative to other energy types. The market share of natural gas is expected to grow slightly over the forecast period, although not to the extent it has historically.

There are differences both over time and between regions in the forecast growth in industrial gas demand. More specifically, the demand for gas is forecast to grow somewhat less rapidly in the early years of the period than in the later years, reflecting in large part the expectation that most of the incremental impact of higher energy prices will be felt in the earlier years. Regionally, it is expected that generally gas demand in the western provinces will grow somewhat faster than in the east, reflecting lower prices for gas and/or somewhat higher economic growth rates.

In most regions, the present forecast of industrial gas demand is slightly higher than that presented in the 1978 Oil Report. For total Canada the present forecast is approximately 2 percent higher in 1980 and 6 percent higher in 1990. More recent historical data and information submitted to this inquiry suggested that the market share for gas, as developed for the 1978 Oil Report, was perhaps a little on the low side. Thus, in most regions, the market share for gas in the industrial sector has been increased slightly, mostly at the expense of heavy fuel oil.

The present forecast is lower than that presented in the Northern Pipeline Report. Specifically, for total Canada the present forecast is approximately 7 percent lower in 1980 and 13 percent lower in 1990. Approximately one-half of this difference results from the exclusion in the present forecast of gas requirements for a major expansion of facilities by SIDBEC, which seemed more likely in 1977. This is consistent with Gaz Métropolitain's forecast submitted to this inquiry. Other reasons for the present forecast being lower include the availability of more recent data and a lower forecast of industrial economic activity.

Thermal Electric Sector

The Board's forecast in this sector includes gas requirements by industry for electricity generation as well as by major and minor utilities in Canada. It was developed by first forecasting the demand for electricity, and then determining the corresponding quantities of each energy type required for its generation. The latter quantities are based on analyses of the evidence, utility expansion plans and appropriate historical data.

Total gas demand for thermal generation in Canada is forecast to grow from 120 Bcf in 1978 to 143 Bcf in 1990 and 153 Bcf in the year 2000. This forecast implies a relatively slow average annual rate of growth of 1.1 percent over the forecast period, as contrasted to an average annual growth rate of 6.9 percent between 1960 and 1976. In general, the relatively low future growth rate results from the expectation that electricity demand will not grow as rapidly in the forecast period as it has in the past, and also that other energy types will be increasingly substituted for gas in the generation of electricity. In general, the demand for gas for the generation of electricity by industry is expected to grow faster than the corresponding demand by utilities. In Ontario, utility demand is expected to decrease over the forecast period as less use is made of the Hearn plant.

The present forecast is essentially the same as the forecast prepared for (though not published in) the 1978 Oil Report. Only minor revisions of gas requirements by industry for electricity generation were made in order to more accurately reflect recently available historical data. The present forecast is, however, significantly lower than that presented in the Northern Pipelines Report. In fact, it is approximately 40 percent lower throughout the forecast period. This is the result of incorporating more recent evidence and views of submittors on this matter.

Petrochemical Sector

The Board's forecast of natural gas requirements for petrochemical production includes feedstock and fuel gas requirements for the production of ammonia, methanol and their derivatives, fuel requirements for ethylene and derivatives and fuel used in the production of chemicals and petrochemicals such as acetic acid, carbon black, sulphides, chlorine and caustic soda. The estimates exclude ethane feedstock requirements for ethylene production in Canada.

The Board forecasts that with the exception of some marginal additional requirements in Ontario of approximately 3 to 4 Bcf, growth in domestic demand for natural gas for use in petrochemical production will come from new plants projected to come on stream in Alberta. The forecast of additional gas-based petrochemical capacity in Alberta is based upon an analysis of evidence submitted to the current hearing, announced plans for the construction of petrochemical plants, estimated domestic and export demand for various petrochemicals and the relative costs and availability of alternative feedstocks. Table 3-9 provides details with respect to petrochemical plants expected to come on stream in Alberta over the forecast period.

Natural gas demand for petrochemical production in Alberta is estimated by combining projections of petrochemical capacity with assumptions regarding feedstock and fuel requirements per unit of production. Specifically, feedstock and fuel requirements per ton of ammonia or methanol is assumed at 36 Mcf per ton. A 1.2 billion pounds per year ethylene plant is assumed to require approximately 4 Bcf of natural gas per year as fuel.

Natural gas demand for petrochemical production in Canada is estimated to increase from approximately 165 Bcf in 1978 to some 237 Bcf in 1990 and 256 Bcf in the year 2000, for an average annual rate of increase of 2 percent.

Table 3–9

PROJECTED PETROCHEMICAL PLANTS IN ALBERTA

Plant	Annual Capacity	Feedstock & Fuel (Bcf/yr)	Expected Date of Completion
Ethylene	1.2 Billion Pounds	4.0*	1980
Methanol	200,000 Short Tons	7.2	1981
Methanol	200,000 Short Tons	7.2	1982
Ammonia	400,000 Short Tons	14.4	1983
Ethylene	1.2 Billion Pounds	4.0*	1985
Ammonia	400,000 Short Tons	14.4	1988
Ammonia	400,000 Short Tons	14.4	1993

* Fuel only

The Board's forecasts published in the 1978 Oil Report and in the Northern Pipelines Report included ethane demand for ethylene production in estimates of gas requirements for petrochemicals. Deduction of ethane demand from these previous forecasts reduces the previous estimate for 1990 to a level about 13 Bcf below the current forecast for the same year. This difference is explained partly by the adjustment to the previous forecast made in the light of evidence and more recent statistics and partly by the assumption in this report that one more methanol plant will come on stream during the forecast period and will use 7.2 Bcf of natural gas per year.

EXPANDED MARKETS

Introduction of Gas into Eastern Markets

Introduction

In the Outline for Submissions, submittors were requested to provide estimates of the extent to which gas could penetrate energy markets beyond existing transmission systems. Such estimates were to include, if possible, assessments of the potential for gas to replace other energy forms; that is, oil (distillate and heavy fuels), coal and electricity. To assist the Board in its assessment of this matter, submittors were requested to provide demand projections and the required city-gate selling price relationship to crude oil required to attain market penetration; to consider the economic feasibility and timing of providing the transmission and distribution facilities required to enable such sales to be made; and an estimate of the related economic impact on competing energy industries.

Views of Submittors

Introduction

The general consensus of submittors favoured expansion of transmission facilities beyond the limit of existing systems, provided such expansion could be justified in economic terms. The Governments of Quebec and Nova Scotia, as well as certain promoters of expansion projects, and a few small independent producers believed that expansion should be considered for other than economic reasons.

Proponents listed among their reasons for expansion producer cash flow problems, eastern Canada's dependence on foreign sources of crude oil and potential improvements in Canada's international balance of payments. No submittor fully quantified the impact of expansion on the balance of payments.

Those who did not favour market expansion identified numerous problems. Paramount were the issues of excess refinery capacity and heavy fuel oil disposition. Absent some action, such as heavy fuel upgrading or export market arrangements, it was generally agreed that heavy fuel oil prices would follow downward any attempt by gas distributors to penetrate the expansion markets through incentive gas pricing practices.

Opponents also stressed the fact that market penetration in the early years would be concentrated in the industrial sector, resulting in lower average per Mcf revenues.

Consuming provinces such as Ontario and Manitoba as well as eastern distributors expressed concern that ex-

pansion could result in their customers subsidizing expansion through the tilting of transmission rates, and went on record as favouring cost-based rates.

One submittor (Ultramar) presented evidence to show that gas expansion would adversely affect employment because refined product marketing is more labour intensive than gas distribution.

The exception among eastern distributors was NCGas who recommended expansion in all regions; that is, adjacent to the existing system and beyond the present limits. In addition NCGas proposed an incentive scheme for gas market development.

The summaries which follow set out in more detail specific comments by certain submittors concerning expansion of gas service beyond existing transmission systems.

AGTL

AGTL, a sponsor of the Q & M pipeline project, testified that it supported the policy of Canadian self-reliance in energy and recommended aggressive development of new gas markets within Canada, particularly in Quebec and the Maritimes.

The Company acknowledged that during its first ten years the Q & M project would be deficient in revenues but contended that in later years the project would produce a revenue surplus. This would require initially a net reduction in field price, absorption of some cost by other consumers of Alberta gas, provincial and municipal tax concessions, plus deferment of normal depreciation and income tax charges.

The Company stated that the aggregate amount of initial utility deficiency would amount to three or four cents per Mcf of all gas produced in Alberta, but beyond the ten-year period the operation would actually provide a net increase equated back to the field price in Alberta of some seven to eight cents per Mcf.

Alberta and Southern

Alberta and Southern made an allowance in its submission for gas expansion in domestic markets, but did not specify where this expansion would occur. The Company stated that such expansion must be economic and that the end consumer should pay the full economic cost of the service. If the extension of a pipeline were considered necessary in the interests of security of supply, then the associated costs should be weighed against the perceived additional security. It was Alberta and Southern's opinion that the ultimate consumer would not likely be willing to pay much of a premium for gas to ensure that security.

British Columbia

The British Columbia submission suggested that any new policy to facilitate the penetration of gas beyond existing transmission systems should not be undertaken at the expense of wellhead value. Furthermore, field prices for sales in new markets should reflect the retail price in the best alternative market available to the producer province, currently the export market.

In cross-examination a witness testified that producer provinces should not be expected to bear the full burden of any subsidy required to achieve market penetration in expanded domestic markets. It was stated that some portion of the cost should be borne by the consumer province.

CIC

The view expressed by CIC was that eastern Canada's dependence on imported oil should be eliminated by implementing a positive national energy plan utilizing Canadian resources administered by federal authorities.

Consumers'

Consumers' submitted that extension of gas service to areas of Quebec and the Maritimes should be undertaken only if such expansion could be shown to be economically viable. In a supplemental submission Consumers' expressed serious doubts as to the economic viability of the project as proposed. Its concern arose basically from the lack of firm and reliable estimates of distribution costs which it stated could be very high, and from its assessment of market potential in the extension areas. Consumers' contended that should extension of the pipeline east of Montreal occur as a result of government decree, and should it require some form of subsidy, this subsidy should under no circumstances be borne solely by existing gas consumers or by the producers. Rather it suggested that under these circumstances such a subsidy should be paid out of general tax revenues.

CPA

CPA noted that displacement of oil imports by other forms of energy was desirable not only to increase Canada's energy self-reliance but also to ensure that energy supplies were allocated to markets most efficiently at their true market value.

To the extent that natural gas could displace oil through comparative economic advantage, it should be encouraged to do so because of the current natural gas surplus in the conventional and frontier areas of Canada. Price cutting as a means of encouraging additional sales of natural gas was not a viable strategy, CPA stated.

The substitution of gas for heavy fuel oil through price reduction would not substantially increase sales in these markets, but would simply give rise to equivalent reductions in heavy fuel oil prices, to the further detriment of already hard-pressed refiner margins.

CPA recommended moving crude oil prices in Canada to international levels as soon as possible and permitting natural gas prices to find their competitive levels. Such developments it felt, would lead to additional outlets in eastern Canadian markets for surplus western natural gas.

Dome

Dome stated that the refining overcapacity in the Quebec and Ontario markets would cause residual fuel to continue to undersell gas and thereby restrict the expansion of natural gas markets.

In other areas of energy use, with the price of crude oil and gas projected to increase to $23/bbl equivalent by 1990, coal and hog fuel would assume a greater role as industrial fuels. This trend would have a dampening effect on the potential expansion of natural gas markets.

Dome submitted that until such time as the refining overcapacity was normalized, gas would not attain the desired growth. Dome concluded that even if natural gas markets were expanded to provide service to new areas in Quebec, the overall impact on domestic demand would only be approximately 5 percent of the total gas demand.

Dome further stated that any expansion of natural gas markets beyond the existing franchise areas should only be attempted in the economically viable and self-supporting areas, without long-term supportive measures from producers, consumers or governments.

Gaz Métropolitain

Gaz Métropolitain, in providing a forecast for the expansion of natural gas into market areas of Quebec not currently served, submitted that certain policies must be in place prior to expansion.

First, the federal government must clearly enunciate a policy objective favouring the use of natural gas in domestic markets. Second, long-term supply contracts of 20 to 25 years must be made available in order to penetrate the industrial market. Third, residual fuel oil surpluses must be removed from the marketplace, but not at the expense of upsetting the economic viability of Quebec-based refineries.

Gaz Métropolitain proposed that in order to accomplish its third policy proposal the following courses of action should be undertaken:

a) Continue to adjust petroleum prices upwards for the short term.

b) Reduce surplus products by switching to greater use of Canadian oil, including synthetic.

c) Ban imports of refined petroleum products.

d) Export heavy fuel oil to the United States for a five-year period.

e) Provide subsidized assistance to Quebec refineries for upgrading facilities to maximize production of light distillates.

f) Encourage refineries to move towards the production of oil products for more profitable sectors such as petrochemicals.

The fourth set of policies required to be in place before expansion could succeed would be the establishment of favorable rate tariff structures and gas prices covering a five to ten-year period which would afford gas a 15 percent price advantage over oil.

Gulf

In its submission Gulf did not assume natural gas expansion in Quebec and to the Maritimes. In its view, if such an extension did occur, it would increase natural gas demand by only 4 percent in 1985. In its opening statement the Company upheld this view stating that it was not opposed to the idea of increased movement of natural gas into eastern Canada so long as it could be done on an economic basis.

Gulf noted that prior to any consideration of gas market expansion in Quebec and the Maritimes, the issues of the price required to induce gas substitution and surplus refining capacity in eastern Canada must be resolved.

Home

Home indicated that the Montreal market offered potential for increased penetration by natural gas, but that such expansion should be based on economic criteria. The Company did not favour mandated fuel substitution; however, if the federal government should decide as a matter of policy that gas expansion beyond existing systems was in the public interest, the cost of such expansion should be financed from national revenues.

Imperial

In its submission, Imperial assumed extension of the natural gas pipeline to Quebec City only. Under cross-examination, the Company stated that it had not carried out detailed studies of the Maritime markets.

With regard to security of supply, Imperial stated that the 15 percent natural gas market potential in the Maritimes was not sufficient to provide security of supply. In this connection Imperial proposed three alternatives which in its view would provide security of supply during a long-term emergency, namely, crude shipments from Vancouver, provision of sufficient oil storage, or construction and preservation of an oil pipeline east of Montreal, even though it might not be used.

Inter-City

Inter-City supported the concept of extending natural gas service in Quebec and to the Maritimes.

Inter-City submitted that in order to penetrate markets in expansion areas gas pricing policy adjustments would be necessary. These adjustments would consist of a reduced Alberta border price to lower gas costs in all market areas including existing markets. As well, in order to induce conversion in the expanded markets burner tip discounts should be offered.

In order to support expansion into primarily uneconomic areas, and to support the incentive prices for gas that would have to be offered, Inter-City proposed that a "natural gas expansion fund" be established. Such a fund would spread the cost burden of supporting new market areas over all forms of government, federal, provincial and municipal, as well as the producer.

IPAC

IPAC said that any attempt to increase natural gas markets beyond the existing transmission system by price reduction would be counter-balanced by a reduction in the price of residual fuel oils. Should the supply of residual fuel oil be restricted to force the use of natural gas, the refineries would either reduce their level of operation or dispose of residual fuel oils in markets outside of Canada.

The consultant, Levy, presented testimony stating that the viability of extending gas service in Quebec eastward from Montreal would depend upon the outlook for alternative energy supplies and the market value set by the prices of such alternative supplies. This would apply to the industrial sector in particular, where the largest volumes were expected to go and must go to support new pipeline construction.

Levy believed that the Canadian interest would be best served by exporting gas to a market where it would attract a price commensurate with its premium qualities. Such a policy would preserve at the same time a segment of the Canadian market for the lower priced residual fuels. Levy further stated that the netback value of natural gas relative to crude oil was always lower where gas and petroleum products competed in distant markets owing to the substantially higher cost of transporting gas versus crude oil. Furthermore, since prices for heavy fuel oil, the major competitive fuel in industrial uses, were typically below the cost of crude and because of the extension markets' dependence on industrial sales, the average revenue of the extension market would be lower than that for the existing system. Therefore, the consultant concluded that extension on the basis of non-commercial criteria would have negative economic impact on western producer revenue and eastern refinery operations by further exacerbating the current refined product surpluses. This applied particularly in the Maritimes where in 1977 refineries were running at an average of 66 per cent of capacity.

Levy said that absent any offsetting government policies, it would be largely eastern Canadian consumers of light oils, such as gasoline and domestic heating fuel who would eventually have to bear the added cost of displacing heavy fuel oil by natural gas in extension markets. Eastern refiners would be forced to increase refined product margins to regain pre-extension earnings rates.

IPAC presented a forecast for the possible extension of gas service into areas of Quebec and Maritimes. IPAC stated that any extension to these areas should only be undertaken if it could be justified on simple economic grounds.

IPAC further stated that should an extension be considered, regardless of the economics, it would require some form of subsidy. In this event IPAC contended that the fol-

lowing key issues must be addressed; namely the costs and benefits of undertaking such a subsidized project relative to other possible alternatives to achieve the same goals of security of supply and national unity, and determination of the required subsidy, as well as determining who will bear the cost of such a subsidy.

Manitoba

The Manitoba submission stated that expansion of Canada's natural gas transmission system beyond its existing markets should be undertaken only when economic. This opinion was consistent with previously expressed views of the Province that transmission rates should be cost-based and reflect the cost incurred to provide the service. The Province believed that the criteria for extending the existing transmission system should be the marketability of natural gas including the added transmission costs, and that none of these costs should be charged to existing customers through the tilting of transmission rates. Furthermore, if a subsidy should be required to finance uneconomic extension beyond the existing system, similar funds should be made available for extension of service to uneconomic regions adjacent to the existing system.

Newfoundland

With respect to the development of markets for natural gas within the Province, the Minister's submission stated that the geography and economic structure of the Province detracted from the opportunity for natural gas penetration outside the largest urban areas. The Government testified that the Province had considerable gas potential but natural gas would not likely be a significant element of the Province's energy demand pattern before the 1990's.

It favoured eastern gas market expansion in the long term, but viewed with concern the immediate impact such a subsidized market might have on surplus refining capacity and the competitive position of adjacent regions. Newfoundland was concerned that a policy to replace oil by natural gas could further endanger the viability of existing refineries. The Province had already experienced the Come-by-Chance closure and was anxious that the viability of its remaining Golden Eagle refinery not be weakened. While it was not the intention of Newfoundland to discourage gas market expansion to the detriment of adjacent provinces, the Province noted it would seek commensurate compensation in respect of any approved subsidy.

The Province acknowledged, however, that eastern market expansion would in the long-term provide incentive for continued exploration and development of potential offshore reserves.

NCGas

NCGas proposed that an incentive discount based on the current flow-back from natural gas exports be implemented for a fixed period of time in order to develop domestic natural gas markets. This incentive discount would be funded by the excess revenue generated by new and renewed export sales and would be used to promote sales to presently unserviced areas in Canada.

NCGas testified that if the present oil/gas price relationship remained constant, an incentive of approximately 28 cents per Mcf for new gas deliveries into new areas would be sufficient to achieve a significant gas for oil substitution.

The incentive funds would be applied against the cost of construction, promotion and sales. Because the incentive would only be paid on new gas delivered, it would constitute in terms of total gas volumes produced only a nominal portion of the producer's present net-back or of tax revenues.

Norcen

In its direct testimony Norcen recognized problems associated with gas penetration of expansion markets. Norcen contended that cost-benefit analysis would be required to weigh the costs of gas penetration against the perceived benefit to Canada of achieving a greater security of supply. The cost of such security of supply should not be borne by either the producer or the consumer alone; it should be subsidized from incremental revenues from new exports. Such an approach would distribute the cost to all those that benefited from these new markets, namely Alberta, the federal government and the producer.

Nova Scotia

One objective of Nova Scotia's energy policy was stated to be to reduce dependence on foreign crude oil. The Province agreed with and fully supported the national energy policy of self-reliance. To this end Nova Scotia proposed that natural gas service be provided to the five large populated areas of Truro, Halifax-Dartmouth, New Glasgow, Port Hawkesbury and Glace Bay-Sydney, as well as to those communities along a route between Amherst and Halifax.

Initial market growth for natural gas in the proposed service area was expected to come from new residential construction and commercial and industrial conversions. Consumption of gas for thermal power generation by Nova Scotia Power Corporation and steam generation for the Point Tupper heavy water plant was included but the decision respecting its use in such facilities would be subject to further economic and political considerations.

The Province stated that the delivery and use of Canadian gas in eastern Canada would be expensive and that its full cost would exceed the ability of the Province to pay. It was felt that a city-gate price at Halifax equal to Toronto would not necessarily ensure required market penetration. The weighted average city-gate price at Halifax in the early 1980's would probably have to be between $2.10 and $2.40 per Mcf. Burner tip values shown in the submission were said to represent the breakeven cost of the least cost alternative energy source - generally petroleum fuels. These breakeven values were based on posted prices, and not actual market prices.

The submission concluded that the project in the initial years would require financial incentives in order to assure cost competitiveness with traditional insecure energy supplies and suggested that this could be accomplished through federal subsidy, lower revenues to producers or increased charges to existing consumers. The Province acknowledged the possibility that it might provide some subsidy.

Ontario

Ontario noted that current proposals to extend natural gas service to those parts of eastern Canada not now served contained various schemes to cushion the burden of construction and transportation costs. Ontario had no wish to deny any part of Canada the benefits of natural gas, but at the same time expressed the viewpoint that Canada should not be extending service to areas where it was clearly uneconomic. Furthermore, the Province said that it did not favour differential Alberta pricing to encourage new markets or the concept that existing customers be asked to pay higher and inequitable transportation charges. Ontario stated it subscribed to the principle of a single cost-based Alberta border price with each market bearing its appropriate cost for transportation.

Ontario identified the current problem as one of reducing eastern Canada's dependence on imported crude oil. Inasmuch as the region has a well-developed oil refining and distribution system, the Province recommended a policy of expanding Canada's oil supply, and seeking ways and means of displacing imported oil with indigenous supply. Ontario did not believe that natural gas would displace a significant proportion of imported crude oil in eastern Canada.

With respect to security of supply, the Province saw no parallel between the Sarnia/Montreal crude oil pipeline extension and extension of gas facilities beyond Montreal. The Province supported crude oil pipeline expansion because of the viable market infrastructure in place in eastern Canada as well as the potential additional oil sands supply capability in western Canada; but acknowledged that current investment in oil sands production is insufficient to accommodate any further eastward expansion.

If a national policy to displace oil products produced from imported crude oil with natural gas were imposed, the Province contended that the source of funds for any required subsidy should be the federal government.

Panarctic

Panarctic expressed the opinion that if it were government policy to subsidize eastern fuel users, such subsidy should be directed to residual fuel oil upgrading. In support of this opinion the Company filed a report prepared by Fluor Canada Ltd., which investigated residual fuel oil upgrading as a means of reducing the available supply of heavy fuel oil.

The submission contended that the present crude oil subsidy destroyed the refiners' incentive to upgrade and presented a modified approach to determining the subsidy whereby the portion of subsidy payable on residual fuel oil would be removed. This change in procedure, in the opinion of the Company, would encourage upgrading.

PanCanadian

PanCanadian submitted that if it were judged to be in the interest of Canada that eastern market expansion should be subsidized, then, as a minimum the federal government, and the governments of Alberta, Quebec and Ontario should each be in agreement to it. Furthermore, the new markets should have a reasonable expectation of paying full commodity value and the burden of subsidy should be shared between the producers, transmission companies, distribution companies, producing provincial governments, consuming provincial governments and the federal government. The Company suggested that such financial support should be for a short-term period with the consumer being responsible for paying the full cost following termination of the program.

ProGas

ProGas set out in its submission a forecast of natural gas requirements for an expanded market case in the province of Quebec. Specifically it forecast the construction of a pipeline eastward to Quebec City and areas adjacent to the pipeline route.

ProGas submitted that such an extension could not in its opinion be justified on purely an economic basis. However, federal and provincial governments might for reasons of their own decide that the pipeline should be extended eastward.

ProGas contended that in order for expansion to occur there must be subsidized gas prices in the expansion area and excess heavy fuel oil must be removed from the marketplace either through exports or upgrading.

Q & M

Q & M submitted that expansion of the existing natural gas pipeline systems to serve domestic markets in the Montreal area and areas east of Montreal in the provinces of Quebec, New Brunswick and Nova Scotia would be economically viable under the following market and pricing assumptions:

- Gas prices at the burner tip in the residential market would be discounted 20 percent below the price of competing oil products for the first ten years of the project. The second ten years would see a 10 percent discount at the burner tip whereupon prices would return to a competitive basis with oil products thereafter.

- Gas prices at the burner tip in the commercial market would be discounted 20 percent below the price of competing oil products for the first six years of operation whereupon the discount would be reduced on a linear basis to zero by the tenth year.

- Gas prices at the burner tip in the industrial market would be discounted 15 percent below the price of competing oil products for the first six years of the operation whereupon the discount would be reduced on a linear basis to zero by the tenth year.

- The necessary distribution infrastructures would be in place to provide an adequate grid network to allow for the projected capture rates in the various market sectors.

- Crude oil prices at Toronto city gate would be at world levels by the start-up date in 1981-82 and natural gas would maintain its current price level of 85 percent relative to crude oil.

- A subsidy or utility deficiency of between three and four cents per Mcf would exist for a period of ten years. Q & M submitted that this utility deficiency was calculated against the total cost of the Q & M system as proposed and would include all distribution and transmission costs, the discounted selling prices for natural gas and any costs related to the expansion east of Alberta of the TransCanada pipeline system required to carry the additional volumes for the expansion market. All of the foregoing costs were divided by the total Alberta gas production to arrive at the three to four cent per Mcf figure.

Under cross-examination Q & M indicated that the associated costs of the proposed extension should not be treated on an incremental basis for rate making purposes, but rather they should be rolled in with existing transmission costs.

Quebec

Quebec's submission stated that the Province's energy balance in 1990 would be noted for the important position occupied by electric power, its sole major energy source. Although the Province was anxious to expand gas usage, the submission noted that factors influencing future requirements such as availability, dependability, transmission facilities and prices were largely determined beyond its provincial borders. Quebec saw an advantage to the immediate construction of transmission and distribution facilities as far east as Quebec City, particularly if gas were to penetrate the market prior to the increasing availability of electric power.

The submission proposed that the present ratio of 85 percent of oil parity be retained in the existing market and that a ratio of 75 percent be established in expansion markets. The Province had set as an objective a 12 percent gas market share in 1990, compared to 6 percent today.

It was stated that the effect of charging any supplementary transportation and distribution costs to new customers would ruin any hope of increasing the use of gas. To make possible the desired market development the Province proposed that part of the additional cost be borne by existing Canadian customers.

In acknowledging the current excess heavy fuel oil problem, Quebec noted that the most economic solution would be export market development. Furthermore, a policy to increase gas expansion before solution of the heavy fuel problem would, at best, risk failure and, at worst, cause refinery shutdowns.

Shell

Shell recommended that expansion of domestic natural gas markets take place on a priority basis and called for a policy that would encourage the replacement of oil by gas within existing franchise areas. Shell further qualified this recommendation by stating that such replacement of oil by gas should take place only where competitive.

Shell's second recommendation was for the expansion of existing gas market areas east of Montreal to include such areas as Quebec City, again indicating that such expansion should only take place if it could be seen to be economically viable. If, however, the expansion proved not to be economic, there might well be other mitigating considerations overriding purely economic considerations, such as security of supply. Shell contended that any subsidies related to this expansion under these circumstances should be shared by the producers, transmission companies, distribution companies, producing provincial governments, consuming provincial governments, the federal government and the consumer.

Shell's third priority for expansion of domestic markets would be to the Maritimes but it stated that such an extension could not be economically justified nor was it required for reasons of security of supply at this time. Shell contended that if expansion to the Maritimes were undertaken for reasons such as security of supply, any required subsidies should be paid from general tax revenues.

Underlying Shell's expansion scenario were two basic assumptions. First, heavy fuel oil would not present a barrier to natural gas penetration of the industrial market and any surplus volumes of heavy fuel oil produced or displaced by gas would be exported. Under cross-examination Shell stated that studies indicated upgrading of residual fuel oil to be uneconomical.

The second major assumption stated by Shell was that the current 8 percent Quebec sales tax on residential and commercial sales would be removed and gas would be priced competitively with other fuels in the marketplace, but without any artificial aids such as underpricing it relative to its true market value.

Sun

Sun submitted that the substitution of natural gas for oil would be a logical approach to realizing energy self-reliance for Canada considering the current trend to increased gas reserves.

In support of its substitution case Sun presented forecasts for natural gas expansion within the province of Quebec. Sun's estimate of potential market penetration assumed that gas would be competitively priced with alternate products, the eight percent Quebec sales tax on natural gas would be removed and the replacement of heavy fuel oil would be mandated. Sun stated however, that any proposal to expand existing transmission systems should only be considered if it were economic to do so.

In regard to its position relative to the possible mandating of natural gas into the expansion market, Sun warned that such a policy must be approached cautiously. Any natural gas price changes that were to occur should be phased in gradually in order to minimize possible economic impact on the refiner and related operations.

TransCanada

TransCanada presented an expansion case for existing franchise areas, and for areas east of Montreal including Quebec City, Sherbrooke and the Maritimes as its "most likely" forecast of gas demand.

In order to achieve the levels of demand projected, particularly for expansion in the province of Quebec, TransCanada saw three main prerequisites.

The first was the disposition of heavy fuel oil supplies from the Quebec refineries. TransCanada submitted that natural gas could not displace heavy fuel oil through price cuts alone, but rather the supply of heavy fuel oil must be reduced from its current level. Under cross-examination TransCanada stated that forecasts of heavy fuel oil production for Quebec refineries indicated that the output of heavy fuel oil from Quebec refineries could be absorbed in the Quebec market within the range of gas forecasts that TransCanada prepared. This situation would only come about, however, if adequate import controls were in place preventing an influx of imported heavy fuel oil to the Quebec market.

The second prerequisite for TransCanada's expansion case was that gas be fully competitive in the marketplace. TransCanada went on to define fully competitive as

meaning gas priced at the same price as competing fuels after conversion costs were paid.

The final prerequisite for penetrating the expansion market was the assurance of long-term supply.

Ultramar

Ultramar submitted that as long as there was surplus heavy fuel oil in the eastern Canadian markets, penetration of these markets by natural gas could only be achieved if there were a significant price advantage to the end-user.

The Company contended that premature gas substitution would militate against rather than enhance self-reliance.

Furthermore, the Company testified that expansion of gas markets into eastern Canada would have a significant impact on employment. According to Ultramar, the number of people employed per billion Btu's of energy sold are as follows:

natural gas –	one worker for 129 billion Btu's
heating oils –	one worker for 71 billion Btu's
propane –	one worker for 24 billion Btu's

The loss of employment would be 140 jobs for every 10,000 barrels per day of oil displaced by natural gas.

Ultramar stated its Quebec refinery was operating at approximately 75 percent of capacity. If gas expansion were to take place the Company would respond by reducing the price of heavy fuel oil to its next alternative market; that is, export. However, at this point in time Ultramar was not very optimistic about securing export markets, particularly in the United States.

Union Carbide

With respect to markets beyond existing systems Union Carbide submitted that inasmuch as the full potential for gas in the Montreal area remained unrealized after 20 years of effort, no major gas network expansion should take place until the marketability of gas in the Montreal market improved substantially. Also, the economics of expansion must be demonstrated.

Union Carbide was opposed to natural gas penetration in extension markets through lowering of gas prices. In its view such an approach would be ineffective because of the existing spare refinery capacity which would militate against market penetration. Union Carbide supported refinery upgrading of heavy fuels if economically justifiable.

Universal

Universal stated that it supported the concept of expansion and suggested that the industry should be forced to build the Q & M pipeline immediately in order to serve gas markets in eastern Canada. The Company stated that it would gladly give up some portion of its revenue to help subsidize Q & M, if necessary.

Views of the Board

The Board's treatment of expansion markets takes into account the statements of the federal government in August 1978 that the fixed relationship in price between natural gas and crude oil does not allow natural gas the flexibility in price to penetrate new markets in Canada. At that time the federal government stated it would enter into discussions with Alberta to obtain the price flexibility needed for market expansion.

In this connection, the Board is aware that a Federal-Alberta Task Force has been formed to establish mechanisms for implementation of the agreed policy objective of encouraging natural gas expansion in eastern Canada. This would be achieved by means of an incentive pricing scheme whereby incremental volumes of Alberta gas would be made available to new markets east of Alberta for less than the present selling value for a fixed duration. Such mechanisms would include appropriate actions by federal and provincial governments and industry to achieve the desired objectives of increased self-reliance.

The Board has made an estimate of the potential sales resulting from the expansion of natural gas service into new market areas in Quebec and to the Maritime provinces. These potential sales volumes are predicated upon specific hypotheses as to the relative prices of natural gas and competing fuels and the disposition of surplus fuel oil existing in these market areas. The assumptions underlying the Board's estimated requirements of the expansion market are outlined in a later section of this chapter. It should be stressed that the assumptions are critical to the achievement of the levels of market penetration estimated by the Board. The Board has not studied the conditions under which these assumptions might materialize, nor is it implying that they will in fact materialize. Nonetheless, at this juncture, the Board deems it prudent to set volumes of natural gas aside for these expansion markets until it

can be demonstrated in a subsequent hearing whether these markets for natural gas exist.

Although the Board did not prepare gas expansion scenarios for areas west of Quebec, it is not precluding the possibility of some expansion occurring, say, in Ontario or Manitoba. The Board has not made any provision in its forecast for extension of natural gas service to Vancouver Island.

Displacement of Petroleum Products

Views of the Submittors

In addressing the problems of displacement of petroleum products by natural gas, submittors believed that potential surpluses of heavy fuel oil could be solved by export, rationalization of current refining operations or by the construction of a residual fuel upgrading facility. There was little evidence presented concerning the problem of displacing light products by natural gas.

Export

The evidence tended to recognize opportunities for exporting heavy fuel oil from Ontario to the United States mid-west, an area not easily accessible to Quebec refineries. Refiners in Quebec could, however, benefit from increased exports out of Ontario by providing replacement barrels into the Ontario market. Submittors agreed that exports of heavy fuel oil to the United States east coast should be encouraged, although Ultramar stated that to enter the market Canadian refiners had to overcome a cost disadvantage of $2 per barrel in competition with Caribbean refiners. Gulf recommended that Canadian officials seek to obtain United States domestic refiner clasification for refineries in eastern Canada in exchange for increased natural gas exports. Such classification would provide available benefits under the United States entitlement program to ease the competitive position of Canadian refiners. IPAC believed that United States authorities would never allow foreign residual oil to seriously undercut markets for United States manufactured product.

Rationalization of Refining Facilities

Evidence was received that individual refiners could reduce yields of residual fuel oil by altering their plant facilities. Processing lighter feedstocks was offered as another way of achieving the same result, although IPAC cautioned that in so doing eastern Canadian refiners would face lower levels of utilization which would lead to higher refining costs. Moreover, refiners pointed out that lighter crude oil is more expensive and feedstock costs would increase substantially. Witnesses also stated that the world supply of light crude oil is less than that of heavy crude oil and will be increasingly difficult to obtain. Refiners argued that, given sufficient time, they could accommodate some measure of gas penetration in eastern Canada but that major outlays for new facilities would be difficult to recover given the current underutilized capacity and the slow growth in markets.

Hycarb, testifying on behalf of Norcen, stated that greater integration of Ontario refinery operations could reduce production of heavy fuel oil. Imperial believed that such a proposal would have an undesirable impact on the competitive position of each refiner and furthermore that it would be contrary to the Restrictive Trade Practices legislation. Hycarb chose as an example the advantages inherent in having Petrosar process less crude in favour of naphtha purchased from refiners. No evidence was received as to how these types of arrangements might be implemented and Petrosar said that such proposals ignored the difficulties of obtaining naphtha of acceptable quality and price for petrochemical production.

Central Upgrading Facility

Panarctic suggested construction of a facility in eastern Canada to upgrade about 100 Mb/d of heavy fuel oil to light products, thus providing for removal from the market product displaced by natural gas and, at the same time enhancing Canada's self-reliance by reducing the volume of imported oil. Panarctic thought that this could be done without additional cost to refiners or consumers since it believed that gas producers would accept lower revenues to obtain a greater Canadian market. Panarctic was unable to identify all of the costs associated with such a scheme but felt they were unlikely to be so large as to jeopardize its economic viability. The company did, however, estimate the cost of upgrading at $4.67 per barrel of plant input. Panarctic's estimate was disputed by Imperial, Shell and Texaco. Imperial estimated that the cost of upgrading would be between $7 and $9 per daily barrel and Shell estimated a minimum of $7.00 a barrel.

Panarctic conceded that the scheme had not addressed problems that might arise with respect to continued operation of the Portland-Montreal pipeline.

Views of the Board

Industrial markets which could be switched from oil to natural gas are not likely to be converted so long as heavy fuel oil from domestic refining operations continues to be the major competitor. Natural gas penetration in industrial markets can be accommodated if, and only if, the petro-

leum products currently supplying this sector can be removed from the market by exportation, product import regulation, upgrading, or by changing refinery feedstocks. Based on the Board's medium case for gas expansion, it does not appear that refiners would have insurmountable problems in adjusting to a lower share of market for petroleum products; however, some refinery investment would be required.

Export

The Board doubts the ability of Ontario refiners to significantly increase exports of heavy fuel oil to the United States mid-west, under the current regime of export pricing. The opportunity to export heavy fuel oil from Quebec and Maritime refineries to the United States eastern seaboard is limited by virtue of existing market circumstance. Caribbean refineries owned by companies with established east coast outlets have a dominant position and would not easily yield market share considering their own current low rate of refinery utilization. This forces Quebec and Atlantic refiners to rely more heavily on domestic markets, where the same competition tends to be less marked. No evidence was presented indicating the likelihood of any significant change in United States market conditions. Indeed, the Board considers that there is a good possibility that severe competition will be the rule for the foreseeable future, bearing in mind the anticipated low growth in international markets and the tightening supply of light crude feedstock. Exports of heavy fuel oil to the United States eastern seaboard under prevailing market conditions would entail low refinery netbacks, for which offsets might be sought through inflationary increases in the prices of light products in the domestic market. There would be no reduction in imports of crude oil so long as the co-produced light products are needed in Canada.

Rationalizing and Upgrading

As an alternative to exporting, the Board accepts that displaced residual fuel might be removed from existing Canadian markets by conversion to lighter products, either centrally as suggested by Panarctic or in facilities installed by individual refiners. Although upgrading might reduce the utilization of refinery capacity and increase unit costs, it has potential to create a new market for Canadian natural gas, and reduce Canada's dependency on foreign energy sources. However, it is important to assess with reasonable accuracy the respective costs of these alternatives. Furthermore, the reduced requirements for crude oil at Montreal could force closure of some of the Portland-Montreal pipeline facilities thereby severely limiting Canada's future continuity of crude supply.

In the absence of clear evidence, it remains to be seen whether the introduction of increasing quantities of synthetic crude oil in the Canadian market will significantly reduce the quantity of residual fuel available for sale or upgrading. If it does, insufficient feedstocks may be available to justify a central upgrading facility of optimum economic size. Moreover, the Board notes that certain refiners have already announced changes to Montreal facilities which would put them in a position to better meet their own anticipated product requirements without necessarily having available feedstock for upgrading in a third party plant. The Board finds that Panarctic's evidence presented in support of the concept of a central upgrading plant was inadequate in several particulars. The study did not include all of the costs of transportation, land, working capital etc. and the inclusion of these expenses would increase the upgrading costs from the proposed level of $4.67 a barrel to about $7 to $9 a barrel. The Board believes that petroleum products displaced from these markets by gas penetration would be most appropriately dealt with by affected refiners adapting their equipment and operation over a reasonable period of time, and consonant with the evolving mix of product demand.

Given the Board's base case for gas expansion, spare crude distillation capacity in eastern Canada would remain at a very high level during the forecast period. The Board believes that discussions concerning the alleviation of this situation should be continued with United States authorities to permit mutually beneficial matching of Canadian supply capability with United States market demand.

Estimates of Gas Demand in Eastern Markets

Whereas previous sections have concentrated on various policy and other considerations related to the introduction of natural gas into eastern Canadian markets, the focus in this section is on actual estimates of the demand for natural gas in these markets. First, estimates of the submittors are presented and discussed, followed by estimates of the Board. In both cases, discussion of results is preceded by brief descriptions of pertinent major assumptions and methodology.

Estimates of Submittors

The Board is pleased with the efforts made by the various submittors in providing estimates of the possible demand for natural gas in eastern Canada. Many submittors noted the difficulties inherent in developing even tentative estimates. Not surprisingly, there are sometimes significant

differences between their estimates, often reflecting differences in assumptions and methodology.

The major assumptions underlying submittors' estimates of gas demand in eastern Canada might be categorized into two areas, i.e., those dealing with the price of gas in these markets, and those dealing with the heavy fuel oil problem.

Most submittors assumed, in developing their natural gas demand estimates, that natural gas would be priced either competitively with or at a price advantage over competing oil products at the burner tip in eastern Canada. It was felt that such pricing would be necessary if there was to be significant gas penetration. Of those submittors assuming that gas would have a price advantage, some assumed that this advantage would be phased out over time. Regarding the heavy fuel oil problem, most submittors assumed that surplus supplies of heavy fuel oil would be eliminated so that natural gas could penetrate the market. More detailed summaries of submittors' views in these areas are presented in preceding sections of this chapter.

In general, submittors relied on a combination of their market experience, judgement, and analysis of the historical examples of other regions in Canada in developing their estimates of natural gas demand for eastern Canada.

One specific methodology used by many submittors, particularly in developing estimates for the residential and commercial sectors, might be called the "components" approach. In this approach, estimates of natural gas demand were built up from estimates of component parts forming that demand. For example, in the residential sector, gas demand was often derived from estimates of future households, broken down into existing and new; estimates of conversions of existing households to gas

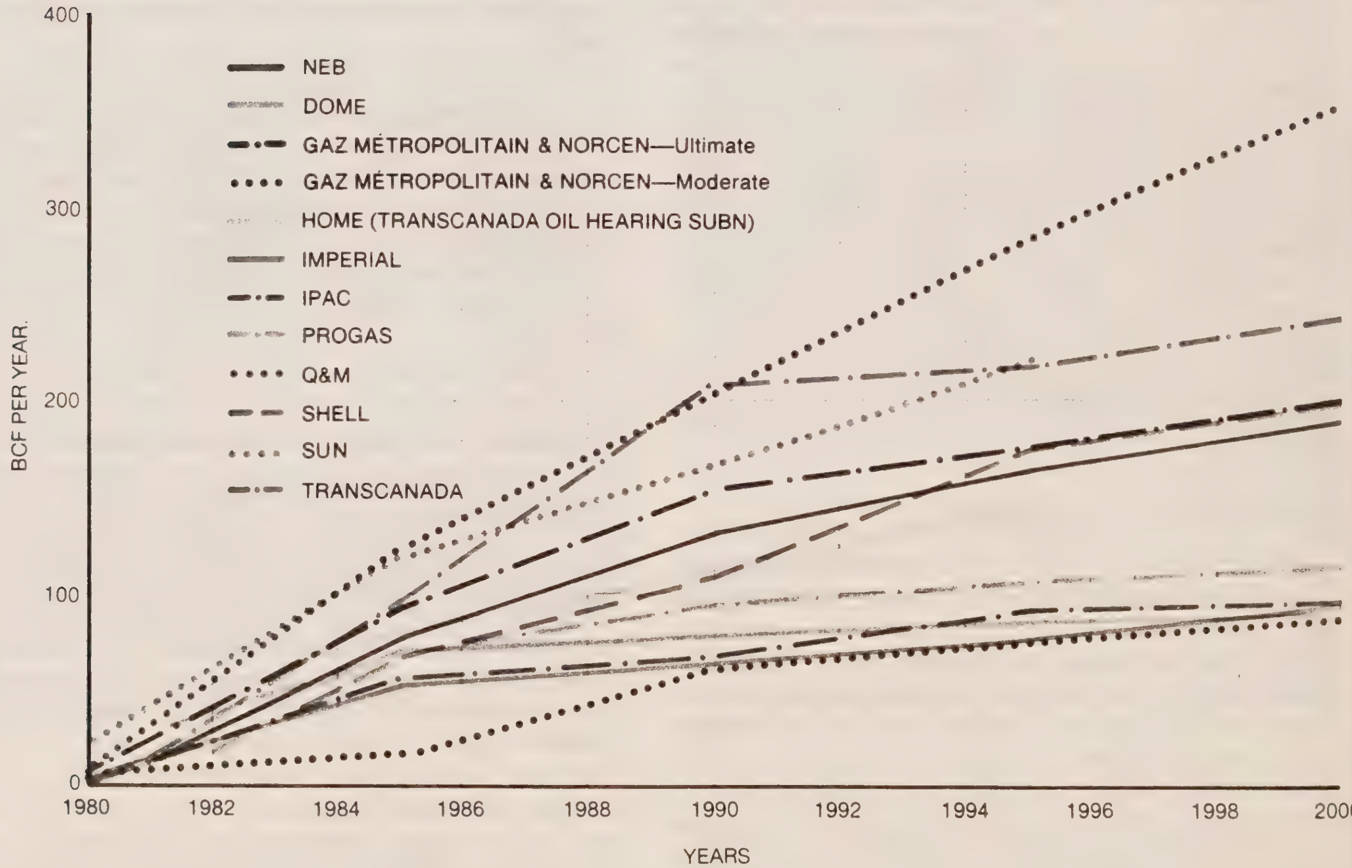


Figure 3-5 **QUEBEC EXPANSION CASE – ADDITIONAL GAS DEMAND**
Comparison of Forecasts

estimates of the penetration of gas into the new household market; and, estimates of average gas consumption per household.

Other approaches to developing the gas demand estimates included examining the total energy market in the regions in question, and determining a share of that market that might reasonably be expected to be captured by gas, given the assumptions made.

Submittors' estimates of additional natural gas sales in eastern Canada under a gas expansion scenario along with the estimates of the Board are compared graphically in Figures 3-5, and 3-6. The estimates made by submittors are discussed in some detail below, by region and market sector. The specific estimates of additional gas sales are presented in Appendix 3-D while in Appendix 3-E they are combined with the various forecasts of the sales without such a market expansion.

Quebec

Residential Sector

The estimated expansion volumes in the residential sector in Quebec exhibit considerable variation over the forecast period, as a result of differences in methodology, assumptions, and the extent of substitution already included in the "base case" gas demand forecasts for the existing franchise area.

Q & M's forecast gas expansion volumes were consistently the highest over the forecast period. Factors contributing to its high forecast included a high gas capture rate for new dwellings and a high conversion rate for existing housing stock. Moreover, Q & M assumed a significantly higher use per dwelling as compared to other submittors, partly as a result of the fact that it assumed that there would be no additional conservation after 1980.

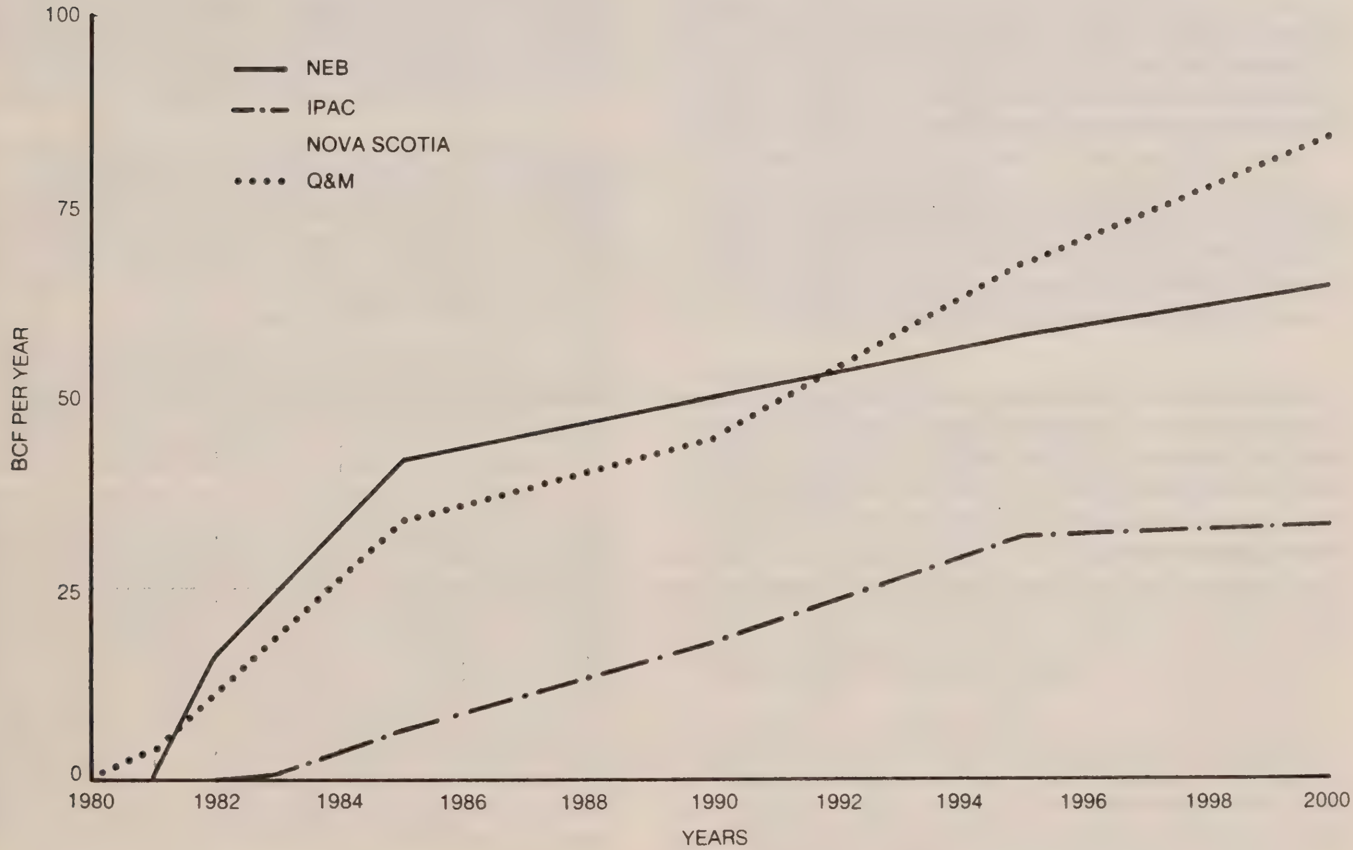


Figure 3-6 **MARITIMES EXPANSION CASE – GAS DEMAND**
Comparison of Forecasts

Gaz Métropolitain's moderate penetration case was on the low side until 1995. This forecast was developed by assuming that total gas demand in Quebec would amount to 15 percent of the provincial energy requirement in the year 2000. The demand for gas in the residential sector will, of course, depend on forecast total provincial energy requirements and the allocation of gas demand to the residential sector. After 1995, Dome's forecast of gas expansion volumes is the lowest; no allowance for expansion of gas demand in the existing franchise area has been allowed for in its forecast.

Several submittors labelled their forecasts as maximum potential forecasts. These submittors included Gaz Métropolitain (ultimate penetration case), Shell and Sun. The labelling of these forecasts as maximum potentials is somewhat tenuous, however, since the forecasts depend on underlying assumptions not all of which may represent the highest feasible limit. For example, Gaz Métropolitain assumed a weighted average consumption per dwelling of 116.3 Mcf per year excluding the effects of conservation, while Q & M's expected forecast assumed average use per dwelling of 139 Mcf per year in the existing gas franchise area, and an average 156 Mcf per year in new Quebec markets, with no allowance for additional conservation. In addition, Shell estimated the gas capture rates for new dwellings underlying its maximum potential cases at 50 percent as compared to 60 percent by Gaz Métropolitain (ultimate case), and 50 percent for Q & M's expected forecast. Furthermore, Shell's forecast did not assume any conversion of existing dwellings to natural gas except for apartments, due to the high cost of laying new lines through established residential areas.

Of the remaining submittors providing information on gas expansion in the residential sector, Imperial provided a breakdown of expansion volumes for the new market only. It would appear, however, that considerable gas substitution has been allowed for in the existing gas franchise area. Comparing its forecast demand for natural gas including gas expansion with those of other submittors shows that after 1985 only AGTL had a higher demand estimate. IPAC provided a forecast of combined residential/commercial gas expansion volumes, for new Quebec markets only. Home adopted TransCanada's forecast of gas expansion volumes submitted to the Board's 1978 Oil Hearing. As can be seen by comparing this forecast with TransCanada's current forecast, residential gas expansion volumes have more than doubled after 1985, although TransCanada's expansion volumes are generally still lower than those of Sun and Shell, and are only a little more than half of Q & M's volume.

While most submittors indicated that light fuel oil would be backed out mainly as a result of conversions to natural gas under assumptions of gas expansion, the demand for electricity was also indicated to be affected. This was expected to occur as a result of gas capture of new dwellings, where electricity is currently capturing 70 to 80 percent of the market. Although some estimates were provided on the amount of light fuel oil backed out, the impact on the demand for electricity was not quantified.

Commercial Sector

As in the case of the residential sector, eight submittors provided estimates of expansion volumes of natural gas in the commercial sector in Quebec. The estimates for the year 2000 ranged from a high of 82.7 Bcf projected by Q & M to a low of 9 Bcf forecasted by Imperial. Shell and TransCanada occupied the middle range with estimates of 46.8 Bcf and 50 Bcf respectively. While Sun submitted forecasts for the period until 1995, its estimate for 1995 was higher than that of any other submittor for the same year. AGTL who adopted Q & M's estimates of expansion volumes projected the highest average annual rate of growth for the period 1978 to 2000 (10 percent), while Norcen's moderate penetration case forecast represented the lowest rate of growth (2.8 percent).

TransCanada, Home, Shell and Sun provided separate estimates of expansion volumes in the existing and new franchise areas of Quebec. Home projected higher additional gas demand in new areas, while TransCanada, Shell and Sun foresaw higher additional demand for natural gas in existing areas.

Q & M's forecast was based upon assuming a 1:10 ratio between the numbers of commercial and residential gas customers in the existing and new areas and a base load of 204 Mcf/year per connection over the forecast period. Conservation was assumed to be incorporated in the estimate of base load and no additional allowance was made for conservation over the forecast period. Imperial's estimates reflected high energy conservation (25 percent in 1985 and 35 percent in 2000). TransCanada estimated energy conservation in 2000 at 35 percent in the new market and 28 percent in the attached market. Its high conservation was partly counter-balanced by a forecast rise in the market share of gas from 7 percent in 1980 to 29 percent in 2000. Shell assumed gas would capture all incremental commercial heating demand of which 60 percent was estimated to be within the present franchise area. Conversions from oil were predicted by Shell to rise from 5 percent of the available market in 1982 to 50 percent by 1995.

Submittors generally assumed that the additional penetration of natural gas would occur mainly as a result of substitution of gas for petroleum products, particularly light fuel oil and heavy fuel oil. Norcen assumed that in both its moderate and ultimate penetration cases, the relative mix of light fuel oil, diesel oil and heavy fuel oil in 1980 would be maintained. This assumption resulted in a slightly higher substitution of gas for heavy fuel oil than for light fuel oil. Home estimated expansion volumes on the assumption that the share of electricity and the volume of light fuel oil in 1980 would be maintained over the forecast period, and heavy fuel oil demand would be kept at a minimum. This assumption resulted in a slightly higher displacement of heavy fuel oil than light fuel oil. Sun provided estimates of heavy fuel oil displacement only. The estimates implied greater substitution of gas for light fuel oil and heavy fuel oil.

Industrial Sector

The industrial sector of Quebec constitutes the largest single potential market for natural gas in eastern Canada. Nine submittors provided estimates of gas demand in this market and although there were significant differences in the various estimates, most saw a possibility for substantial growth in demand over the next 20 years.

Of those submittors providing estimates of industrial gas demand for both the existing and proposed new gas franchise areas of Quebec, the "moderate penetration scenario" provided by Gaz Métropolitain and Norcen generally constituted the lowest estimates of demand. For the early years of the forecast period TransCanada provided the highest estimates, while for the later years, the highest estimates were provided by Q & M. Three submittors, Dome, Imperial and IPAC provided estimates for the proposed new gas franchise area only.

The differences between submittors' estimates often resulted from a combination of different estimates of the total energy market in the industrial sector, and different estimates of the penetration rate for gas. Some estimates seem quite optimistic, particularly regarding the penetration rate for gas. TransCanada, for example, estimated that, by 1990, natural gas would capture over 90 percent of its estimate of gas-competitive total energy demand in the industrial sector of the proposed new gas franchise area of Quebec. Others, such as Shell, did not foresee gas achieving such rapid penetration rates.

Regarding the effects of gas penetration on other energy types, most submittors felt that gas would for the most part displace oil and that most if not all of the oil displaced would be heavy fuel oil. Q & M was the exception in that it felt gas would replace roughly equal amounts of light fuel oil and heavy fuel oil.

Maritimes

Residential Sector

Nova Scotia and Q & M were the only two submittors who provided estimates of residential gas demand in the Maritimes. Q & M's forecast was slightly higher than Nova Scotia's forecast of maximum potential gas requirements in the residential sector.

The first step in the forecast submitted by Nova Scotia was the identification of breakeven prices for natural gas, or that price at which the consumer would pay the same price for his heating requirements as if he had installed a traditional oil heating system. Potential gas demand was then analyzed assuming that natural gas would be priced at or below the average breakeven price of approximately $5 per Mcf in 1982 for new installations.

Q & M's forecast assumed discounts for natural gas at the burner tip of 20 percent for the first ten years of operation, 10 percent for the second ten years, and zero thereafter, relative to competing oil products in the residential sector.

In forecasting residential gas demand in the Maritimes both submittors followed the approach indicated in the introduction to this section, although Nova Scotia's forecast is one of maximum potential.

Commercial Sector

Q & M and Nova Scotia provided estimates of natural gas demand in the commercial sector in the Maritimes. Nova Scotia submitted estimates for the period to 1995 only. Both submittors provided separate estimates for New Brunswick and Nova Scotia. Q & M projected demand for gas in the commercial sector in the Maritimes to increase from 0.1 Bcf in 1981 to 9.0 Bcf in 1995 and to 12.2 Bcf in 2000. Nova Scotia estimated demand to increase from 0.7 Bcf in 1981 to 11.9 Bcf in 1995.

Q & M's forecast is higher than that of Nova Scotia for 1985 and lower for 1990 and 1995. This difference is partly explained by Q & M's assumption that gas will have a 20 percent price advantage at the burner tip for the first six years after which the advantage will gradually reduce to zero by the tenth year. Nova Scotia assumed gas price in the commercial sector at or below a breakeven price of $5.50 per mcf.

Industrial Sector

Of the two submittors providing estimates of natural gas demand in the industrial sector of the Maritimes, Nova Scotia was considerably more optimistic than Q & M particularly in the earlier portion of the forecast period. Part of the reason is that Nova Scotia assumed that a heavy water plant at Point Tupper, Nova Scotia, would convert to producing steam using natural gas rather than heavy fuel oil, with resultant gas requirements of some 8.8 Bcf per year throughout the forecast period. Nova Scotia was also more optimistic than Q & M regarding the capture rate for natural gas in the industrial total energy market in the Maritimes.

Thermal Electric Sector

In developing their natural gas demand estimates for the Maritimes, both Nova Scotia and Q & M assumed that two oil-fired electricity generating plants in Nova Scotia would be converted to burn natural gas. Both submittors assumed the conversion would take place as soon as gas became available in the area, which would substantially add to the base load of the gas pipeline. The two submittors' forecasts differed in that Nova Scotia assumed that gas used for thermal generation would be phased out over the forecast period, while Q & M assumed that the generation plants would continue to be gas-fired.

Estimates of the Board

The Board concurs with the view expressed by many submittors that forecasts of market expansion by a given energy type into a new market area are fraught with difficulties and uncertainties even greater than those associated with ordinary energy demand forecasts. However, in order to assure itself that adequate provision has been made for potential new domestic markets for natural gas, the Board has attempted to develop tentative estimates of possible gas demands under several "gas expansion" scenarios. Specifically, gas demand estimates have been prepared, by market sector, for areas in Quebec not presently served by gas and for New Brunswick and Nova Scotia. As well, gas expansion scenarios have been developed for the existing gas franchise area of Quebec. For each of these regions "high", "base", and "low" projections have been developed.

The general approach used to obtain the various estimates has been to postulate a set of assumptions considered to be necessary for gas to achieve significant penetration into the new markets, and then to project the resulting volumes of gas. The conditions under which these assumptions might materialize have not been the focus of study. Furthermore, in making these assumptions, the Board is not implying that they will in fact necessarily materialize. Discussed below are the major assumptions that have been made followed by an outline of methodology. The section concludes with a discussion of results, by market sector and region.

The Board agrees with the view presented by many submittors that in the present circumstances, the two major factors inhibiting the further expansion of the natural gas market into eastern Canada are the price of gas vis-a-vis the price of competing fuels and the current and expected availability of heavy fuel oil. The Board realizes that gas market expansion will require various policy measures in these areas and that the degree of gas market penetration will depend on such policies. As a corollary tentative estimates of future gas sales in the new markets can show wide variations reflecting different sets of explicit, or implicit, policy assumptions in these areas.

With regard to prices, it is recognized that natural gas has to be competitive in the new market areas to ensure the penetration of the market by gas. For the purposes of this study, the Board has assumed a city-gate gas price approximately 70 percent of the refinery-gate crude price east of Ontario on a Btu content basis. Further, it is assumed that this will result in burner-tip prices which will encourage gas expansion into these new market area. It is also assumed that the price advantage for gas will be gradually phased out towards the end of the forecast period.

It is assumed that the available competing fuels, particularly heavy fuel oil, will be satisfactorily disposed of, so that their prices will not be lowered in order to maintain markets and prevent gas penetration. The Board has presented its views on some considerations in this area in an earlier section of this chapter.

Given the above assumptions, the Board's starting point in developing its base case gas expansion estimates for Quebec and the Atlantic Provinces was the base case forecasts of total energy demand for these regions, which are discussed in the first part of this chapter. Specifically for each region and market sector, the base case forecasts were broken down into geographic subregions based on an examination of appropriate historical information. Regarding Quebec, two subregions were broken out, namely, the existing gas franchise area and the proposed new gas franchise area. For the Atlantic region, the base case energy demand projections were subdivided to obtain the volumes corresponding to the geographic

areas of New Brunswick and Nova Scotia which would be serviced by natural gas.

Given the above, the assumption was then made that, for each subregion and market sector, total energy demand in the gas expansion case would be roughly equal to total energy demand in the base case. Thus, the task in estimating gas expansion case volumes then focussed on determining, for each subregion and market sector, appropriate changes in the market shares of the various energy types, relative to the base case, given the assumed changes in relative energy prices and availability of gas.

For the existing gas franchise area of Quebec, important tools of analysis in developing the gas expansion case market share estimates were econometric studies regarding the responsiveness of the market share of gas to changes in the relative price of gas. For the proposed new gas franchise areas in Quebec and the Maritimes, the natural gas market share estimates were guided more by examinations of the manner in which gas penetrated various markets in Canada historically, following its initial introduction. The areas examined most closely were the existing gas franchise area of Quebec, and the provinces of Ontario and British Columbia. In all market share estimates developed, the evidence presented to the current inquiry was drawn upon extensively.

It should be noted that for purposes of this projection it was assumed that natural gas would back out oil products exclusively, i.e., that electricity demand would be unaffected by the introduction of gas into eastern Canada. Although there are major areas where gas and electricity are not competitive, and although government policies would probably be directed towards displacing oil rather than electricity, it is quite possible that some electricity might be backed out as a result. To this extent, the Board's estimates of oil products displaced as a result of gas expansion may be somewhat overstated.

As noted, the Board has prepared high and low gas expansion case estimates as well as medium case estimates given the substantial uncertainties involved. A summary of the various estimates is as follows:

Table 3–10

ADDITIONAL GAS DEMAND ASSOCIATED WITH GAS EXPANSION
(Bcf/year)

	1985	1990	1995	2000
Quebec				
High Case	88.2	168.4	240.8	310.8
Base Case	78.0	131.8	165.7	189.4
Low Case	71.2	109.7	123.8	125.4
Maritimes				
High Case	44.3	58.9	76.2	94.6
Base Case	42.1	50.5	58.2	65.0
Low Case	40.7	45.4	47.7	48.8
Total				
High Case	132.5	227.3	317.0	405.4
Base Case	120.1	182.3	223.9	254.4
Low Case	111.9	155.1	171.5	174.2

As indicated it is the Board's estimate that additional gas volumes in eastern Canada could be some 25 percent higher or 15 percent lower in 1990 than its base case estimates, depending upon the underlying assumptions made.

The base case estimates for the market expansion in Quebec and for the Maritimes are shown in Appendix 3-D and presented on the following pages. These volumes, when consolidated with the base case volumes for existing markets, result in the tables in Appendix 3-E which show the estimates of total natural gas net sales, including gas expansion, for both Quebec and Canada.

The Board's estimates of the volumes of heavy fuel oil and light fuel oil that might be displaced under its base gas expansion case are presented by region in Appendix 3-F.

Quebec

Residential Sector

Gas demand under the assumptions of the gas expansion case is expected to grow at an average rate of 7.1 percent over the period 1980 to 2000, reaching a market share of 20 percent in the year 2000, as compared to 9 percent of the total Quebec market for the base case forecast. By the end of the forecast period, total expansion volumes are estimated to reach 42 Bcf, of which 19 Bcf are expected to materialize in the existing franchise area.

Additional gas demand in the existing franchise area of Quebec was estimated by predicting the responsiveness of consumers to a decrease in the burner-tip gas price of approximately 17 percent from the assumed price levels underlying the base case forecast. This price decrease results from the assumptions that the Quebec sales tax on natural gas in the residential sector will be removed, and the Montreal city-gate gas price will decrease to 70 percent of the refinery gate price of crude oil. It was estimated that in the residential market associated with the existing gas franchise area, natural gas would increase its share in the year 2000 from 13 percent in the base case to 21 percent as a result of such a price decrease.

In the new market area, it was assumed that the market share held by natural gas at the end of the forecast period would approximate the gas share at that time in the existing market area. The rate of gas penetration in the new market would be faster than the historical rate of gas penetration of the Quebec residential market, but would be slower than the corresponding historical rates in Ontario and British Columbia.

For the purposes of this case, all the impact of gas expansion was allocated to refined petroleum products. Consequently, oil demand backed out may be overstated somewhat, since it is expected that some impact on the demand for electricity would occur, mainly as a result of increased gas capture of new dwellings. Light fuel oil is expected to bear most of the impact of gas expansion, with an estimated drop in demand of 18 Mb/d in 2000, while the demand for heavy fuel oil drops by 3 Mb/d from the forecast base case levels.

The Board's estimate is quite close to TransCanada's most likely case and to Shell's forecast of potential demand, but over the long run, it is higher than Gaz Métropolitain's ultimate penetration case, and substantially lower than AGTL's expansion case.

In comparing total expansion volumes, including expansion of gas demand in the existing gas franchise area, the Board's estimate is higher than Gaz Métropolitain's ultimate penetration case. The Board's figures are somewhat lower than the expansion volumes forecast by TransCanada and Shell, because the Board's base case forecast already incorporates capture of some of the market which TransCanada and Shell assume will only be penetrated under their expansion assumptions.

Commercial Sector

In the commercial sector, a reduction in the Montreal city gate price of natural gas, coupled with the removal of th 8 percent sales tax on gas sales is estimated to reduc the burner-tip price of natural gas to a level about 19 per cent below the base case. This reduction in gas price ca be expected to lead to gas penetration in markets pres ently served by light and heavy fuel oils in the existing an new franchise areas.

As a result of the additional penetration by natural gas i existing and new franchise areas, the market share of ga in Quebec is estimated to increase from 7.7 percent i 1978 to 21.7 percent in 2000. Net sales of gas under thi case are estimated to increase from 15.5 Bcf in 1978 t 91.0 Bcf in 2000, for an average growth rate of 8.4 per cent per annum. This rate compares with the rate c growth of 4.1 percent per annum under the no expansio base case, in which the market share of natural gas wa estimated at 9.1 percent in 2000.

In the light of an analysis of substitution possibilities in th existing and new franchise areas and an evaluation of ga penetration in provinces where gas was cheaper relativ to oil, it is concluded that natural gas would displace ligh and heavy fuel oils in proportion to their present use i the commercial sector. The Board's assumption that na ural gas would penetrate markets served by both light fu oil and heavy fuel oil is consistent with the evidence sub mitted at this inquiry.

Industrial Sector

It is estimated that in 1981, under conditions favourable t increased gas penetration in both existing and propose new gas franchise areas in Quebec, industrial gas de mand might be some 7 Bcf higher than the no expansio base case estimate (as discussed in the first part of thi Chapter) rising to 104 Bcf higher in year 2000. Underly ing this estimate is a projection of gas market share whic rises to approximately 31 percent of the Quebec industri energy market in 2000 under the gas expansion scenari as contrasted to 17.5 percent in the base case. It is as sumed that all incremental gas sales will be at the ex pense of heavy fuel oil.

Regarding the existing gas franchise area, the mark share of gas might increase from an estimated 27.5 per cent of that market in year 2000 under the no expansio base case to 37 percent of the market under the gas ex

pansion scenario. This estimate is based on the assumption that the burner-tip price of gas relative to heavy fuel oil will be approximately 15 percent lower in the gas expansion scenario than in the no expansion base case in the market throughout the forecast period. Volumetrically, it is estimated that an additional 47 Bcf of gas might be demanded in the year 2000 in the existing gas franchise area of Quebec, given the assumptions of the gas expansion case.

Regarding the proposed new gas franchise area of Quebec, for purposes of this study, it is estimated that the market area of gas might increase quite rapidly from zero in 1980 to just under 20 percent of the industrial total energy market in this area in 1985 and to approximately 37 percent of the market in the year 2000. Volumetrically, it is estimated that 57 Bcf of gas could be demanded in the industrial sector of the proposed new gas franchise area of Quebec in the year 2000.

This projected rate of gas penetration is believed to be possible, although it may be somewhat optimistic. It implies considerably faster penetration than occurred historically in the existing gas franchise area of Quebec over a comparable period, and somewhat faster penetration than has occurred in the industrial sector of British Columbia. For most of the forecast period the penetration rate is, however, somewhat lower than that achieved historically in Ontario. It is felt that the estimated rate of penetration is perhaps most optimistic in the early portion of the forecast period, where for example after ten years it is forecast that gas will have a larger market share than was the case even in Ontario. The evidence presented at this inquiry does, however, support the view that such penetration rates as have been projected for the industrial sector of the proposed new gas franchise area of Quebec are possible, given the pricing and other assumptions made.

Maritimes

Residential Sector

In the Maritimes, demand is forecast to increase from 0.9 Bcf in 1982 to 11.0 Bcf in 2000, with growth over the period 1985 to 2000 averaging 7.3 percent per annum.

Demand for natural gas was estimated by applying the share expected to be obtained by natural gas, to the forecast total energy requirements in areas where gas availability was assumed. Of the total residential market in the Atlantic Provinces, it was estimated that Nova Scotia and New Brunswick energy requirements comprised approximately 74 percent. Moreover, 55 percent of the energy market in Nova Scotia and New Brunswick was assumed to have gas available, based on the proportion of the population situated close to the proposed gas pipeline. Hence, of the total energy market in the Atlantic Provinces, roughly 41 percent was assumed to have gas availability. The gas share developed for gas penetration in the new market of Quebec was then applied to this market to yield forecast gas demand in the residential sector.

As for Quebec, the total impact of gas expansion in the Maritimes was allowed to fall on the demand for refined petroleum products. Virtually all of the impact of gas expansion in the Maritimes is borne by light fuel oil. In the year 2000, approximately 6 Mb/d of light fuel oil is expected to be displaced.

As previously mentioned, Nova Scotia and Q & M were the only submittors providing sectoral forecasts of gas demand assuming gas availability in the Maritimes. The Board's forecast of residential gas demand is quite close to the forecasts of these submittors in the period to 1995. However, for the year 2000, Q & M's forecast was considerably higher than that of the Board. Nova Scotia did not submit a forecast beyond 1995.

Commercial Sector

In the commercial sector of the Maritimes the potential for gas to replace light and heavy fuel oils was estimated using a methodology similar to that described for Quebec. In particular, the market share of gas was determined after analyzing substitution possibilities in the new gas franchise areas in New Brunswick and Nova Scotia. Further, the substitutable portion of energy demand in the two provinces, that is, the portion which would have access to the proposed pipeline was assumed to be 70 percent. Using these assumptions, the market share of natural gas in the Atlantic Provinces is estimated at 4.3 percent in 1985 and 10 percent by 2000. Net sales of natural gas are estimated to increase from 3.0 Bcf in 1985 to 10.3 Bcf in 2000, for an average growth rate of 8.6 percent per annum.

Industrial Sector

The Board estimates that demand might increase quite rapidly from almost 12 Bcf in 1982 (the assumed first year of gas service) to 47 Bcf in the year 2000. It is assumed that all gas penetration in this sector will be at the expense of heavy fuel oil.

Of the total estimated gas volumes in the industrial sector,

8.8 Bcf for each year of the forecast period results from the assumed conversion of a heavy water plant in Nova Scotia from heavy fuel oil to gas for the purpose of producing steam. This assumption is consistent with the views of Nova Scotia as expressed at this inquiry. Regarding the rest of the estimated gas volumes, they result from an assumed penetration of gas into the proposed gas franchise areas of New Brunswick and Nova Scotia comparable to the rate of gas penetration used for the proposed new gas franchise areas in Quebec.

Thermal Electric Generation

For purposes of developing gas expansion estimates for the Atlantic region, the Board has included gas requirements for thermal electric generation in Nova Scotia of approximately 13.5 Bcf in 1985 dropping to 5.4 Bcf in 1990 and zero in 1995. This usage would back out some volumes of heavy fuel oil. Both Q & M and Nova Scotia included thermal gas requirements in their natural gas forecast for the Atlantic region. Further, analysis of Nova Scotia Power Commission's future expansion plans indicated that, given the price assumptions, conversion of two oil-fired plants to natural gas for electricity generation would not appear unreasonable. The phasing out of gas for electricity generation towards the end of the forecast period is consistent with Nova Scotia's views.

Chapter 4
Supply / Demand Balance

VIEWS OF SUBMITTORS

Submittors who provided estimates of potential productive capacity from all reserves in the conventional areas of Canada also submitted a supply/demand balance of some form. Some of the balances were simply an overlay of the projected productive capacity and the expected demand forecasts. Other balances considered the effect that unproduced gas in the early years would have on the productive capacity in later years. Only a few submissions provided a true "balance" of supply and demand until deficiencies were forecast to occur.

AERCB

AERCB provided in its submission not only an overlay of productive capacity (adjusted to reflect lesser production in early years) and projected demand, but also a true "balance" of supply and demand under the constraints of the current Alberta protection policy. The 110 Tcf ultimate potential case illustrated that significant deficiencies in productive capacity would occur by 1992, whereas the 130 Tcf ultimate potential illustrative example depicted deficiencies by 1994. However, the expected production under Alberta's 30-year protection policy departed from the demand curve in 1985 in the 110 Tcf case and in 1992 in the 130 Tcf case. In its methodology, AERCB assumed that regions outside of Alberta would produce at capacity and that the total impact of balancing supply and demand would be borne by the Alberta supply.

Alberta and Southern and Canadian-Montana

The Manecon study undertaken for Alberta and Southern and Canadian-Montana presented an overlay of "Maximum Supply South of 60°" and "Domestic Demand plus Licensed Exports." This illustration indicated that shortages would occur by 1996. The study pointed out, however, that if the excess supply indicated was not assigned to new markets, exploration and development activity would likely decline and consequently the first year of deficiency would likely occur earlier.

AGTL

AGTL compared its three forecasts of productive capacity with its forecast of total requirements. It did not present any precise evidence regarding the effect of constraining production to the requirements forecast. It should be noted that AGTL's estimate of total requirements included a 472 Bcf per year requirement for Pan-Alberta and Q & M proposed exports plus Q & M expansion markets. The production capacity estimates included expected deliverability of Mackenzie Delta reserves. Case 1 (2 Tcf/yr finding rate) demonstrated first deficiencies occurring in 1997; Case 2 (2.6 Tcf/yr finding rate) demonstrated first deficiency in 2000, and Case 3 (4 Tcf/yr finding rate) demonstrated no deficiencies within the forecast period.

Amoco

Amoco compared its supply and demand forecasts and concluded that no deficiencies would occur until well beyond the year 2000. It stated that in fact there would be some 0.6 Tcf/yr excess capacity in the year 2000.

CPA

CPA's only comparisons of supply and demand were in the illustrative examples of its deliverability test. CPA adjusted its deliverability to account for unused capacity when supply exceeded demand. Including its hypothetical incremental export of 400 Bcf/yr for eight years, both of CPA's illustrations of deliverability which included deliverability from frontier areas demonstrated a surplus beyond the year 2000.

Gulf

Gulf presented three supply/demand balances for British Columbia, Alberta and East, and total Canada respectively. It felt this was a necessary refinement because certain pipeline and contractual restrictions were present which resulted in a surplus in one area with a deficiency in the other. This approach resulted in an overall balance between supply and demand until 1994 when a deficiency occurred in the Alberta and East area. Gulf's approach included adjustments to account for the unproducedgas reserves in the earlier years of the forecast.

Home

Home compared its potential productive capacity forecast with its total demand forecast and concluded that there would be surplus capacity beyond the year 2000.

HBOG

HBOG said that the point in time when gas deliverability from the conventional areas could not meet projected demand would be 1994, if limited markets were assumed, and 1997 if markets were assumed to be unlimited. It stated further that it anticipated that in the limited market case, the carry-forward of unused surplus deliverability in the early years would delay the date of deficiency by approximately one year.

Imperial

Imperial matched supply and demand for as long as possible from western Canada supply, carrying forward unused producibility from the early years. In its study, deficiencies first occurred in 1993.

IPAC

IPAC did not attempt to balance supply and demand. However, its illustration of surplus deliverability over expected demand demonstrated that the first deficiencies would occur in 1999.

Norcen

Norcen did not attempt to balance supply and demand; however it did present comparisons of its supply forecasts and demand forecasts. By comparing Norcen's "Base Case Demand" with its "No Additional Markets" supply, the first year of deficiency would be 1998. A comparison of the "Maximum Substitution Case" with the "Additional Markets" supply indicated the first year of deficiency would be 1995.

PanCanadian

PanCanadian compared its forecast of non-frontier production with its forecast of total requirements. This comparison indicated that the first year of deficiency would be 1999.

Polar Gas

Polar Gas prepared its supply/demand balances on two bases. Its first presentation compared supply capability with total requirements. This comparison demonstrated minor deficiencies in 1988 and 1989 and then growingdeficiencies commencing in 1992. Polar Gas also prepared three supply/demand balances in which only the volumes of gas sufficient to meet demand were produced. Its base case balance demonstrated deficiencies commencing in 1994. Polar Gas prepared two additional market balances, assuming 10 percent and 20 percent displacement of oil by gas respectively, plus incremental markets in British Columbia and Quebec in both cases. The 10 percent displacement case indicated minor deficiencies in 1988 and 1989 and growing deficiencies commencing in 1991 while the 20 percent displacement case indicated growing deficiencies commencing in 1986.

ProGas

ProGas compared its total forecast of supply with its two requirements cases. Excluding additional Quebec markets, the first year of deficiency was shown to be 1996. Including additional Quebec markets, the first year of deficiency was 1995.

Shell

Shell presented a comparison of its supply and demand forecasts which included an adjustment to the deliverability potential to account for the unused deliverability in the early years. This comparison demonstrated that the first year of significant deficiency would be 1998.

TransCanada

TransCanada balanced supply and demand by "rolling ahead" unused capability from the early years. Its comparison of the resulting adjusted capability and its total requirements demonstrated that the first deficiency would occur in 1997.

VIEWS OF THE BOARD

The Board's forecast of gas supply from the conventional areas is compared with the Board's forecast of Canadian demand plus remaining authorized export volumes in Figure 4-1. In preparing this supply/demand balance, the Board studied the availability of gas supplies to meet total demand by considering three segments of the total Canadian and export market namely, Alberta including exports south from Alberta, British Columbia including exports at Huntingdon and east of Alberta including all other exports. All export licences were adjusted to allow for removal of total licensed volumes, as shown in Appendix 4-B.

As indicated in the second footnote to Appendix 4-B, an assumption has been made that certain export licences would be amended to permit the makeup of volumes not taken in prior years where such makeup is not permitted by existing licence conditions. This would require, upon application, authorization by the Board and approval of the Governor in Council. The total volume of such makeup gas is some 440 Bcf.

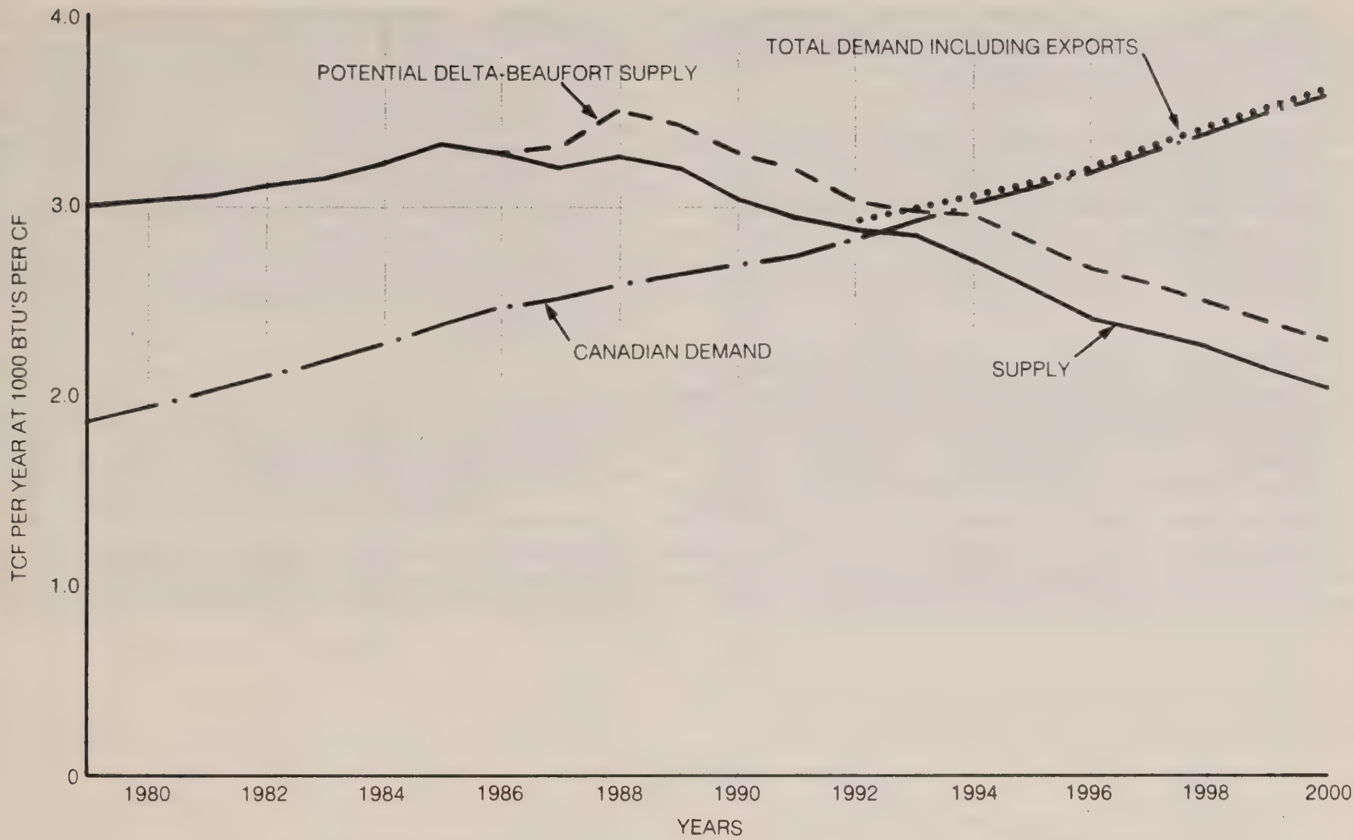


Figure 4-1 **GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS NEB Forecast**

The demand for gas in the above-mentioned market areas is summarized on page 1 of Appendix 4-A. The domestic demand for gas in Alberta including fuel for its distribution is shown separately from the AGTL requirement for fuel to transport gas to other Canadian and export markets.

For the purposes of this illustration the Board included eastern market expansion demand in the domestic demand east of Alberta.

The forecast of reprocessing shrinkage requirements at the three major straddle plants at Cochrane, Empress, and Edmonton provided by Dome and summarized on page 2 of Appendix 4-A was considered reasonable and was adopted by the Board. The future ethane extraction shrinkage at Waterton was calculated by the Board based on evidence submitted and the Board's forecast of deliverability from the Waterton field.

The forecasts of deliverability from controlled reserves are summarized by system on page 3 of Appendix 4-A and discussed in Chapter 2. The volumes shown in each column supply specific markets discussed in the following paragraphs.

Deliverability forecasts for the various sources of supply available to satisfy Alberta demand including exports south from Alberta are summarized on page 4 of Appendix 4-A and can be described as follows: deliverability of Alberta's major and minor utilities as discussed in Chapter 2; the Board's estimate of Alberta and Southern deliverability less its sales to Columbia Gas and its Pan-Alberta contracted sales; the Board's estimate of total supplies under Westcoast Licence No.GL-4; Canadian-Montana's estimate of supply from its permit fields; the Board's estimate of TransCanada's Alberta sales, AGTL fuel and Empress reprocessing shrinkage based on TransCanada throughput; the Board's estimate of deliverability from deferred gas reserves; the Board's estimate of deliverability from shallow uncommitted Alberta gas, other uncommit-

ted Alberta gas and Alberta reserves currently beyond economic reach; and the Board's estimate of deliverability from Alberta reserves additions.

The sum of these forecasts of supply in Alberta exceeds the total demand in Alberta as shown in Column 10 on page 4 of Appendix 4-A and the excess volumes of supply are assumed to be available to supply British Columbia and east of Alberta when these regions require the gas.

To determine the need for this additional Alberta gas in British Columbia, the Board examined the fixed supply sources for British Columbia. Summarized on page 5 of Appendix 4-A, these forecasts of supply include the Board's forecast of Westcoast's deliverability from its total supply area including all established reserves in British Columbia, the southern Territories and its Alberta supply area; the Board's forecast of deliverability available from Pan-Alberta's reserves after making allowance for Pan-Alberta's sales east of Alberta; Alberta and Southern's estimate of its sales to Columbia Gas; and the Board's forecast of deliverability from British Columbia reserves additions. Comparing this total forecast of deliverability with the total British Columbia demand, including the authorized exports at Huntingdon, the Board concluded that there will be deficiencies in certain years of the forecast period in British Columbia. These deficiencies in British Columbia are treated as demands on surplus Alberta deliverability.

Before allocating any of the surplus Alberta deliverability to British Columbia, the Board also determined the need for surplus deliverability east of Alberta. The forecasts of deliverability from sources that supply markets east of Alberta are summarized on page 6 of Appendix 4-A. These forecasts include the Board's forecast of deliverability

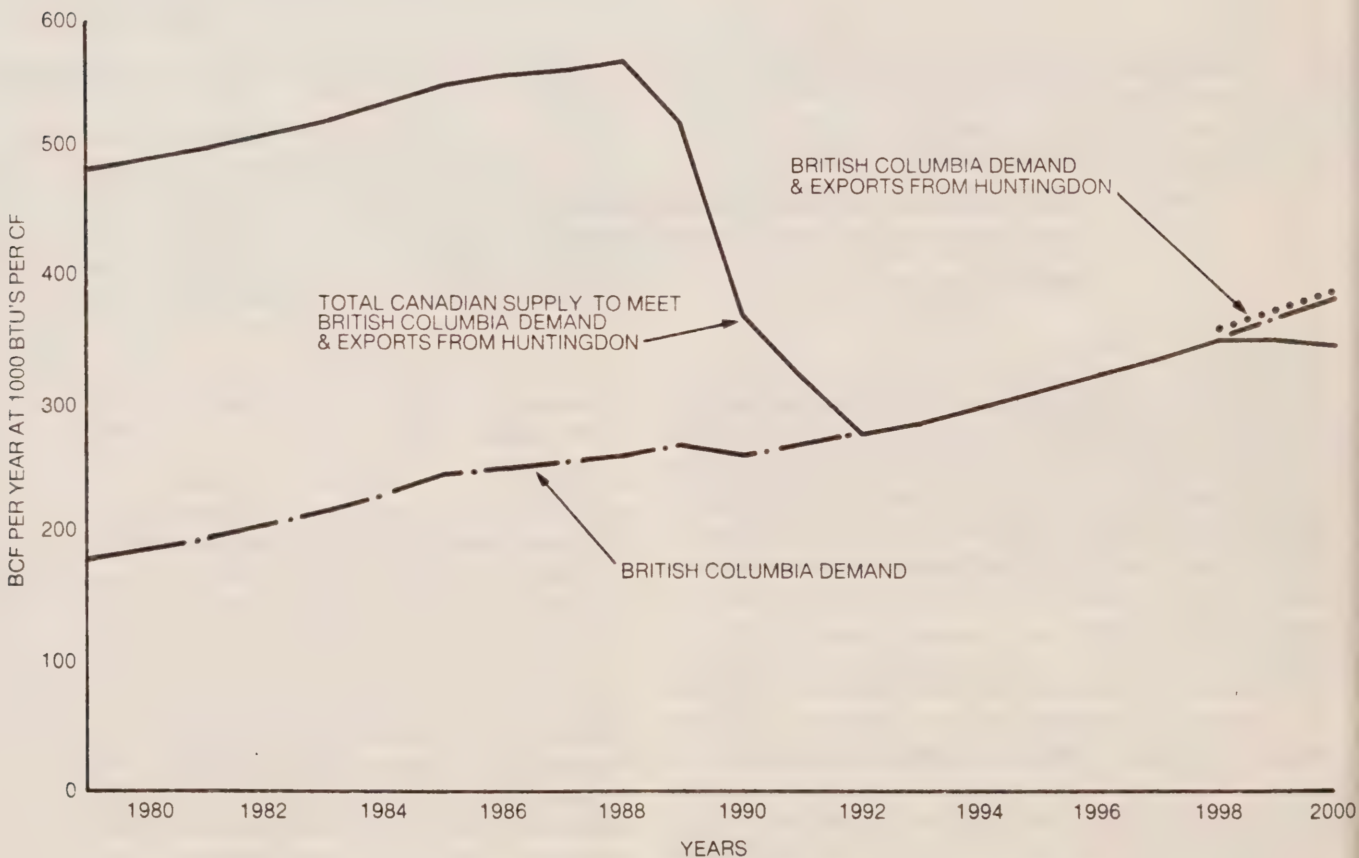


Figure 4-2 **GAS SUPPLY/DEMAND BALANCE FOR BRITISH COLUMBIA NEB Forecast**

from TransCanada's controlled reserves less the Board's estimate of TransCanada's Alberta sales, the Board's forecast of the AGTL fuel requirement to transport TransCanada's gas, and the Board's forecast of total reprocessing shrinkage at Empress based on the forecast of TransCanada throughput; SPC's forecast of Many Islands Pipelines' deliverability; the Board's forecast of Pan-Alberta sales east of Alberta; production east of Alberta as discussed in Chapter 2; and the Board's forecast of deliverability from Saskatchewan reserves additions. This total forecast of supply is capable of satisfying total demand east of Alberta including authorized exports shown on page 1 of Appendix 4-A until 1984 when a deficiency first occurs. This deficiency continues to grow throughout the forecast period and can be partially satisfied by the surplus Alberta deliverability determined earlier.

Thus any gas deliverability surplus to either Alberta or British Columbia demand, including exports, could be allocated as shown on page 7 of Appendix 4-A to markets in British Columbia and east of Alberta as and when required. The Board assumed that the necessary additional capacity in available pipelines connecting British Columbia with Alberta reserves would be constructed when required. It can be seen from page 7 of Appendix 4-A, that after satisfying British Columbia and east of Alberta demands from 1979 to 1990, there would remain volumes of gas, shown in Column 8, which provide a temporary overall surplus to Canadian demand. In this schedule these volumes are assumed not to be produced between 1978 and 1990 and are converted as required to a forecast of deliverability starting in 1991 and allocated to British Columbia and east of Alberta based upon the proportion of the unsatisfied demand which is attributable to each of these regions.

Since the Board deferred deliverability from the temporary overall surplus supplies from 1979 to 1990 until 1991 and

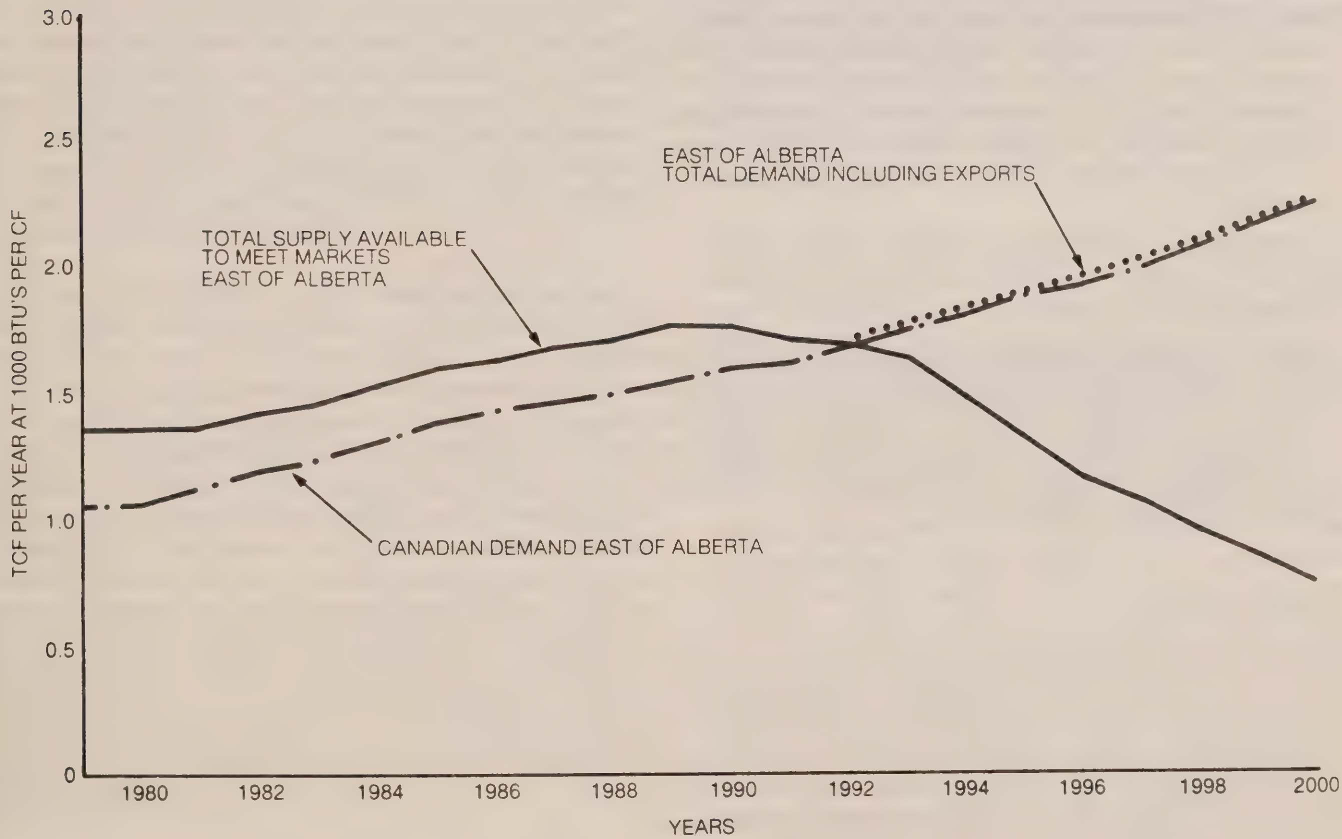


Figure 4-3 **GAS SUPPLY/DEMAND BALANCE FOR EAST OF ALBERTA**
NEB Forecast

later, adjustments had to be made to the Board's forecasts of deliverability from uncommitted and trend reserves in Alberta. The surplus was first removed from the Alberta trend deliverability and any additional surplus was removed from the total Alberta uncommitted deliverability. The total effect of the adjustments to these forecasts is detailed on page 8 of Appendix 4-A.

The Board's total Canadian supply/demand balance is shown on page 11 of Appendix 4-A and is illustrated in Figure 4-1. Total Canadian conventional supply can theoretically meet total Canadian demand plus authorized exports until a deficiency appears in 1993.

It should be noted that the above forecast of supply to meet total demand does not contain any limitations which could result from the implementation of the Alberta protection policy. AERCB's "availability for contracting" test makes use of supply contract information filed with AERCB on a regular basis. Without access to all of the contractual information, it is not possible to make an accurate calculation of this restrictive test or to project the likely results of the test into the future. In evidence submitted, AERCB estimated that expected production under Alberta's 30-year protection policy would not satisfy total demand after 1985 in its 110 Tcf ultimate potential case nor after 1992 in its illustrative 130 Tcf ultimate potential case. Furthermore, the Board notes that AERCB intends to review the Alberta protection policy at an upcoming hearing.

Alberta

Having in mind the location of the greatest portion of the gas reserves from the conventional producing areas and the AERCB protection formula, it is perhaps stating the obvious to say that the requirements of that province will be fully met over the period of the forecast. This has been shown on page 4 of Appendix 4-A.

British Columbia

The supply/demand relationship for the Province of British Columbia is presented on page 9 of Appendix4-A and is displayed in Figure 4-2. The total forecast of supply as previously discussed includes those fixed supplies from British Columbia, the southern Territories and Alberta destined to satisfy the total British Columbia demand as shown on page 5 of Appendix 4-A and those additional supplies of Alberta gas calculated on page 7 of Appendix 4-A. The total demand, under the assumptions employed, can be met until a deficiency appears in 1999.

East of Alberta

The Board's assessment of the gas supply which may be available to meet requirements east of Alberta is presented on page 10 of Appendix 4-A and illustrated in Figure 4-3. The gas considered available for this projection includes the supplies, previously discussed, from page 6 of Appendix 4-A and the additional gas from Alberta calculated on page 7 of Appendix 4-A.

As may be seen from page 10 of Appendix 4-A and Figure 4-3, total demand east of Alberta, including authorized exports, can be met until 1993 when a deficiency of 117 Bcf occurs. This deficiency continues to grow and becomes 1495 Bcf by 2000.

Chapter 5
Surplus

SURPLUS DETERMINATION PROCEDURES

Introduction

The Board in its hearing order stated that the subject matter of the inquiry included;

> "Consideration of methods of determining the volume of gas which may be surplus to the reasonably foreseeable requirements in Canada and authorized exports, taking into account the criteria for determining surplus set forth on page 77 of the 1975 Board Report on Canadian Natural Gas Supply and Requirements"

This chapter provides a brief summary of the considerable material put forward on this topic by submittors to the hearing, followed by the Board's outline of the procedures it will use in determining the existence and magnitude of a natural gas surplus. Following this are calculations and illustrative examples, using the surplus tests procedure, of the quantities of natural gas that may be surplus as of 31 December 1978.

Information and testimony put forward at this hearing to some extent went beyond the strict consideration of a surplus determination procedure, to touch upon matters such as the merits or disadvantages of potential new projects. While the Board appreciates the information submitted and the testimony given on matters outside of the established scope of the hearing, it was not the purpose of this inquiry to consider and decide upon specific applications which are before the Board or which may be coming before the Board. No decision to authorize the export of natural gas or the construction of new pipeline facilities is forthcoming from this inquiry. The Board, therefore, is not prepared at this time to make judgments with respect to evidence put forward during the hearing on costs and benefits associated with potential additional exports. These matters can be considered in hearings of specific applications.

Views of Submittors

Alberta and Southern

Alberta and Southern did not provide an explicit export formula but recommended that the Board's existing 25A4 surplus formula be replaced with a policy which recognized deliverability rather than reserves as the supply criterion. Alberta and Southern recommended that the amount of exports permitted should be based upon the difference between deliverability and demand over the forecast period, in the present case, from 1978 to 2000.

Alberta and Southern suggested that a calculated surplus could be allocated to four demand categories:

1. All or part of the surplus to future Canadian consumers;

2. Substitution to displace imported oil in markets currently serviced by gas or in areas to which service might be extended;

3. Renewal of export licences;

4. New exports.

Alberta and Southern suggested that in evaluating applications for natural gas exports, the Board should recognize that gas could help to minimize the balance of trade deficit resulting from the import of oil and to service foreign debt incurred to finance energy investment. Alberta and Southern stated that every effort should be made to capture the gains from trade in energy products as is done for other products. It was also submitted that, in view of the potential substitutability of alternative energy sources, gas exports should be considered, so that foreseen surpluses were not left without a market. Alberta and Southern held that export licence renewals were important when considering the current high unemployment level in Canada, and submitted that the employment multiplier for the gas industry was above average, in the range of four to eight. Alberta and Southern stated that, apart from security of supply concerns, there was no reason why Canada should attempt to be self-sufficient in energy. Alberta and Southern held that market forces should determine whether increased domestic gas should be used to back out oil imports.

Considering continental energy needs, and the importance of a healthy United States economy to world trade,

Alberta and Southern stated that Canada should maintain natural gas exports to the United States consistent with Canada's own needs, thus reducing somewhat the United States reliance on OPEC oil.

Amoco

Amoco stated that the protection provided by 25A4 was excessive and had resulted in a gas supply surplus. Amoco recommended that the Board determine the exportable surplus, first by examining and providing for current requirements and then by protecting future requirements. In order to protect current requirements, Amoco recommended the adoption of a 20A1 formula. To protect future requirements, Amoco suggested that the Board project the trend gas reserves required to meet future incremental increases in demand, and then project the reserves required to meet the demand in the 20th year. According to Amoco's procedure, actual finding rates on a cumulative basis in excess of the projected requirements would be exportable subject to Amoco's "Trend Gas Export Formula". This formula would be used for four years to calculate an exportable surplus unless there were a significant change in the data base supporting the analysis.

Amoco's "Trend Gas Export Formula" was

$$E = (TC - RC)\frac{t}{4} - EC$$

where, E is the export volume authorized in the year

TC is the cumulative trend gas developed

RC is the cumulative trend gas required

t is the number of years, increasing from 1 to 4 over the four-year period

EC is the volume of cumulative exports authorized during the four-year period

Amoco stated that the potential cash flow from presently shut-in reserves was necessary to encourage the enormous investments required to secure a long-term supply of natural gas.

Bow Valley

Bow Valley supported short-term exports of natural gas to assure the continued high level of exploration and development activity and the future well-being of the petroleum industry in western Canada. Bow Valley stated that there were substantial surplus reserves of natural gas over and above the domestic requirements of Canada.

Charles Caccia, M.P.

Mr. Caccia, Member of Parliament for Davenport, submitted that Canada needed more gas to ensure the security of energy supply, to displace imported oil in eastern Canada and to provide fuel for processing industries. He recommended that the Board should assess Canadian demand over a longer period than 30 years before authorizing exports. Mr. Caccia stated that natural gas was a national resource being developed by means of tax incentives and other measures financed by Canadians, that it should be available only to Canadians to serve Canada's national objectives and it should not be exported.

CARC

CARC addressed a wide range of issues dealing with the development of Arctic resources. With regard to natural gas exports, CARC submitted that conservation must be viewed as another supply option. CARC stated that exports of non-renewable resources would handicap efforts to build a Canadian industrial base by increasing the cost of critical energy inputs in the future.

Canadian Hunter

Canadian Hunter stated that surplus reserves and deliverability existed in Canada and that it was in the public interest to encourage marketing of that surplus. Furthermore, Canadian Hunter submitted that Canadian gas consumers would receive more protection with respect to available gas supply if surplus gas was exported than if no additional exports were allowed.

Canadian Hunter stated that additional export markets would allow the industry to continue to explore for and develop additional reserves in a timely manner so that those reserves would be available for use in the Canadian market when required.

Canadian-Montana

Canadian-Montana adopted and supported the submission of Alberta and Southern to this hearing.

Canadian-Montana believed that, upon timely application by a licensee for an extension of an existing licence, the Board should give favourable consideration to that application, on a priority basis, against other applications which might be before the Board at that time for new export quantities. The Board was also urged, in determining the surplus over a period of years, to set aside a certain quantity of gas for licences that might expire in the future.

CPA

CPA held that the Board's present 25A4 calculation was working to the detriment of Canada and the industry by creating an excessive set-aside due to its inflexibility.

CPA submitted that the national interest would be served by sustaining or increasing current levels of exploration and development through the generation of cash flows from export sales of surplus gas. The CPA stated that the exploration and development process could provide real security of supply for Canada's future requirements.

CPA proposed a two-step procedure to calculate the exportable surplus. The first condition for licensing a new export volume would be that forecast deliverability equal or exceed forecast demand for a minimum of ten years. The CPA's second condition was that the new export volume not exceed the estimated reserves surplus. CPA stated that this reserves surplus (or deficit) should be determined at the time of the application according to a 25A1 variation of the 25A4 current surplus methodology.

CPA further recommended that the reserves and deliverability estimates used in the above tests include frontier natural gas volumes that could reasonably be expected to be connected to markets within ten years. CPA suggested that new export licences be issued for only a relatively short term, up to ten years, and that all new licences be conditioned to allow exportable volumes to be diverted to Canadian use if required to meet domestic demand. CPA stated that any deemed surplus should be closely monitored by the Board so that potential excesses as well as deficiencies would be recognized quickly.

CPA emphasized its view that more years of protection of domestic requirements could be lost if exploration were to decline than would be lost by the comparatively modest incremental exports needed to keep exploration activity at a desirable level.

CPA stated that medium-term supply requirements for Canada appeared secure, thus placing the country in a position to consider export market opportunities. CPA estimated a current deliverability surplus of about 800 MMcf/d and stated further that there were large volumes of unconnected reserves.

CPA stated that additional sales of natural gas should be achieved by securing new markets rather than through price cuts, and held that short-term exports could stimulate a continuation and expansion of the present exploration momentum.

In view of the near-term United States natural gas supply situation, CPA held that exports would direct gas to the highest-value markets and utilize transmission capacity that already existed or could be readily expanded.

The main benefits of natural gas exports cited by CPA were: a positive balance of payments impact; additional tax and royalty receipts for governments; and additional revenue flow to industry which could finance future energy programs and provide jobs and other benefits.

CWF

CWF did not recommend a specific formula or protection procedure and submitted that the Board should not develop an export formula at this time because too much uncertainty existed as to the nature and duration of the present excess of production capacity.

CWF did not believe any case for exports could be made at this time, and suggested that the present over-supply was short term, and did not constitute a surplus. CWF pointed out that natural gas was a finite fuel, for whose use there was no end in sight, and made reference to the implications of having to replace exported volumes with more expensive supplies. CWF recommended that the Board conduct cost/benefit analyses of gas exports before authorizing any export in the future.

Chieftain

Chieftain supported the IPAC submission and submitted that further exports of surplus natural gas were essential to provide the cash flow and economic stability required by industry to sustain the development of Canada's energy potential.

CIC

With respect to a domestic market protection procedure, CIC stated that Canada did not possess a true surplus of natural gas and that no additional natural gas exports should be authorized. CIC said that the issues pertaining to establishing an export formula were too important and complex to expect them to be amenable to a simple mathematical solution such as 25A4. CIC's view was that supplying Canadian markets should take priority over gas going to export markets, both on a short-term and long-term basis, including giving federal authorities the power to override private contracts and allocate reserves to Canadian markets.

CIC stated that it agreed with the criteria set out on page 77 of the Board's 1975 Gas Report for calculating or de-

termining surplus. However, CIC felt that three more criteria should be added. CIC suggested firstly that the determination should also recognize the finite nature of non-renewable resources, their location, their importance to Canadians in these northern latitudes and the availability and cost of substitutes or alternatives, if any. Secondly, the procedure should be fair to consumers. Thirdly, it should recognize the importance of the creation of jobs in Canada and the desirability of utilizing Canadian resources for that purpose rather than exporting the resources in raw form.

CIC stated that the Board should consider Canada's future natural gas supply and requirements balances for a minimum 30-year period, rather than the 22-year period (1978-2000) examined in the present inquiry.

Consolidated

Consolidated did not suggest a new export formula nor did it suggest principles upon which gas exports should be judged. Using the 25A4 procedure, including allowance for remaining exports after 1982 and fuel, losses and shrinkage, Consolidated calculated a surplus of 10,350 Bcf.

Consumers'

Consumers' recommended that the NEB and responsible provincial authorities collectively assess prospective supply/demand balances and conservatively judge the desirability of increasing or decreasing exports in the light of their perception of the short and long-term national interest.

Consumers' was against additional long-term exports. While it agreed that increased exports could tend to increase short-term supplies, it pointed out that increased exports would not result in increased long-term supplies for the domestic market.

Consumers' assumed a less rigid position towards short-term exports because it felt the supply/requirements balance could be estimated with reasonable accuracy in the short-term, and stated that such exports might be in the public interest. Consumers' held that existing export licences should be honoured.

Dome

Dome forecast a large surplus of natural gas from both a deliverability and reserves standpoint. Even assuming no new reserves additions and no frontier gas supply, a surplus of deliverability over demand was forecast until 1985. Over the period 1979 to 1985 Dome calculated a surplus amounting to 2.5 Tcf. Assuming reserves additions of 3 Tcf per year over this period, total additional surplus deliverability in excess of 11 Tcf was forecast over the period ending in 1998.

Dome's proposed surplus calculation formula was:

D − R = ES, where:

D = natural gas deliverability from Canadian reserves of gas on an annual basis, having regard to trends in reserves additions, lags in connection rate, average contract rates of take, and the future decline in reserves once connected.

R = requirements for natural gas in Canada, plus authorized exports.

ES = exportable surplus.

Under this procedure, Dome suggested that the Board determine whether an exportable surplus exists for each year of the licence term applied for.

Dome suggested that the Board review periodically the balance of deliverability and requirements in the light of changing circumstances and condition any new licences with a provision to allow for future increases or decreases in the exportable surplus should a prior forecast of deliverability or requirements prove to have been substantially in error.

Dome pointed out that with no new exports, exploration and development activity would diminish. Dome stated that only by providing additional domestic and export markets would Canada's security of supply be assured through maintaining or increasing the momentum of exploration. Dome submitted that receipts from natural gas exports would offset the growing balance of payments deficit stemming from inevitable crude oil import volume and price increases.

Dow

Dow stated that short-term exports of natural gas resources surplus to Canadian needs could lead to the orderly development of the gas industry. Furthermore, Dow said that such development was required to ensure that future domestic demand would be satisfied.

Dow co-sponsored the natural gas supply/demand forecast submitted by Dome and agreed that there was natural gas surplus to Canadian requirements.

Dow recommended that the export of natural gas should be encouraged after the best Canadian use had been considered. Dow stated that energy exports should be used as leverage to negotiate trade agreements for products upgraded in Canada and called for bilateral free trade for a selected group of petrochemicals.

Dow further pointed out that increased domestic consumption of natural gas had the potential to improve the Canadian balance of payments and the domestic economy in general.

Foothills

Foothills submitted that the NEB should take into account on the supply side of the supply/requirements balance the reserves and deliverability in the Mackenzie Delta - Beaufort Sea because the Northern Pipeline Act and the Northern Pipelines Report demonstrated the probability of an early pipeline connection to that supply area.

Great Lakes

Great Lakes submitted that methods of determining an exportable surplus should specifically provide that priority be given to exports authorized under existing licences. Great Lakes stated that no new exports should be authorized if they could jeopardize exports under existing licences. Great Lakes proposed that the Board should consider extending existing licences prior to issuing new export licences. Great Lakes submitted that if any new exports were authorized, preference should be given to utilization of existing transmission systems or incremental expansions thereof for transporting them.

Gulf

Gulf recommended the abandonment of the 25A4 formula or any variation of it, stating that it did little, if anything, to ensure that the necessary reserves additions were secured. Gulf did not recommend a specific formula. Rather, Gulf suggested a process whereby security of supply was defined within the self-reliance objective for total energy. Gulf submitted that once security of supply was appropriately defined, the additional natural gas reserves that would have to be brought into production, including frontier reserves, could be determined.

Gulf pointed out that the supply/requirements calculations for British Columbia and for Alberta and East should be done separately, as there were certain pipeline and contractual restrictions that could result in a surplus in one area while there was a deficiency in another. Gulf contended that natural gas exports could contribute to the attainment of self-reliance by providing the cash flow necessary to increase exploration and development of natural gas and other energy sources. Gulf stated that export markets were required for the frontier areas to ensure their economic development.

Home

Home recommended a two-part test incorporating consideration of reserves and deliverability. In its Surplus Calculation test, Home recommended a 25A1 formula whereby: surplus = remaining marketable reserves − (current year demand $\times 25$) + total authorized exports. In its second test, its Export Determination test, Home suggested that if the first test showed a surplus of marketable reserves over Canadian requirements, export potential be determined by subtracting total demand (including authorized exports) from potential productive capacity. Export potential would be multiplied by an arbitrary factor less than unity to determine the volumes allowable for new exports. In Home's example, the arbitrary export factor used was .75.

Home submitted that only short-term exports, up to five years, should be allowed.

Home pointed out that short-term natural gas exports (for example 5 years) were the most desirable solution to the oversupply situation in Canada, provided suitable arrangements could be made to protect Canadian interests. Benefits cited by Home included optimum utilization of existing transportation facilities, earning of foreign exchange, and maintenance of a high level of petroleum exploration and development, with consequent positive overflows into other sectors of the Canadian economy. Home stated that additional cash flow generated from short-term exports would stimulate frontier exploration.

HBOG

HBOG recommended authorizing additional exports if a surplus of established remaining reserves and sufficient annual surplus deliverability existed.

HBOG's proposed procedure was as follows:

- Determine established remaining reserves in Canada. Include established reserves in frontier areas at such time as they are reasonably expected to be developed.

- Forecast total Canadian natural gas demand, including authorized exports for the 20-year period following the date of the application. HBOG contended that a 20-year

protection period was fully adequate since a large ultimate potential existed to protect Canada's long-term needs.

- Calculate whether there was a surplus of reserves over the cumulative 20-year demand.
- If a reserves surplus existed, then forecast, for the term of the export application, deliverability from established reserves and from projected reserves additions in conventional and frontier areas.
- Compare forecast deliverability with forecast demand to determine annual surplus volumes.
- Additional exports could be authorized if a surplus of established remaining reserves and sufficient annual surplus deliverability existed. The terms of the export licence should ensure that the volumes and annual rates be compatible with the calculated surplus volumes.

HBOG stated that there was a current deliverability surplus of 350 Bcf/year which would gradually diminish if markets remained limited.

HBOG cautioned that it would not be prudent to assume that export markets would be readily available in the future. Hence, HBOG recommended that the present opportunity be used to establish and develop supply relationships in the export market, utilizing the surplus natural gas which HBOG said was available.

HBOG submitted that additional markets would be required to bring about significant early development of frontier natural gas deliverability. HBOG, argued that early development of frontier supplies provided assurance that frontier gas would be available when required to meet Canadian needs in the future. HBOG added that exports would have a favourable effect on Canada's balance of payments position and act as a general stimulus for the Canadian economy.

Imperial

Imperial did not submit a specific export calculation formula. Rather, Imperial recommended interim increases in Canada's exports of natural gas provided these additional exports did not extend beyond a period for which the Board was satisfied that adequate supplies would be available for Canadian market, including those supplies from frontier regions when transportation programs were firm.

Imperial was in general agreement with the views of th Board regarding the principles and characteristics of procedure for detemining surplus, as published on Pag 77 of the 1975 Gas Report. It stated that if the Board di initiate a new formula, flexibility to deal with changing cir cumstances would be enhanced if it was used as a guid rather than as a rule.

Imperial agreed that determination of supply should b based on deliverability, and stated that deliverability fore casts should include all likely sources of supply includin the frontier regions when transportation viability wa demonstrated.

Imperial supported energy conservation and efficient en ergy use, but did not agree that an export procedur should explicitly reserve for Canadians any benefits fron conservation restraints undertaken by Canadians. It sub mitted that adding a further set-aside of reserves to mee a demand that was not expected to materialize woul work against the economics of supply development.

Imperial submitted that there was a current surplus of nat ural gas producibility in Canada of 0.4 Tcf/year or abou 1 Bcf/day which would continue through the earl 1980's. Thereafter, the surplus was forecast to decline and approach zero in about 1992. According to Imperia after 1992, supplies from the Southern Basin would nc be adequate to meet forecast demand. Estimated variabil ity of the supply forecast showed that Southern Basi supplies could be inadequate to meet demand as early a 1984 but might be sufficient to meet demand until afte 1995.

In the case where no additional exports were allowed, Im perial estimated that the year when Southern Basin sup ply would no longer meet demand was 1993, one yea later than the additional interim export case.

Imperial stated that additional interim exports would en courage a high level of exploration and development i the Southern Basin, permit increased use of existin transmission capacity and assist in the pre-building c southern sections of the Alaska Highway pipeline systen thereby enhancing the opportunity to connect reserves i the Mackenzie Delta – Beaufort Sea area.

Imperial also made reference to the favourable impact ac ditional exports would have on national wealth, Canada' balance of payments and government revenues.

IPAC

IPAC agreed that the method for calculating future Canadian requirements should utilize projections of deliverability rather than having regard to reserves only. IPAC's proposal was to forecast deliverability firstly with likely reserves additions, and then with conservative reserves additions, and compare deliverability with forecast demand.

IPAC found that with a very conservative forecast of reserves additions, a basic exportable surplus of 11,760 Bcf existed between 1978 and 2000, and a surplus of 7,658 Bcf existed between 1978 and 1988. With these forecasts, IPAC stated that additional exports of up to 7 Tcf over a ten-year period could be safely granted. IPAC stated that the actual term of the licence would be considered at the time of the hearing and all relevant factors taken into account.

IPAC submitted that a substantial surplus of developed gas existed in Canada and would continue to exist in the future if incentives for exploration and development were maintained.

IPAC cautioned the Board that any unreasonable conditions in the export licences relating to possible curtailment of supply would render it difficult or impossible to enter into satisfactory sales contracts with United States buyers.

IPAC submitted that increased exports would bring economic benefits to all Canadians and would, in addition, enhance the security of supply of natural gas to serve Canada's long-term requirements by further identifying and developing Canada's energy base.

IPAC held that if additional exports were allowed, there would be no reason to impose natural gas upon Canadian interruptible industrial markets which were presently utilizing cheaper residual oils. This would allow Canadian refineries to operate at a higher load factor, and would allow Canadian manufacturers to continue to benefit from the use of lower cost residual fuel oils.

IPAC stated that additional exports of natural gas surplus to Canadian needs would create substantial economic benefits to Canada and also would assist in making feasible delivery systems for northern Canadian gas when required.

IPAC pointed out that failure to take advantage of the present opportunity to retain and develop United States gas markets could well result in an inability to do so in the future, as competitive energy sources such as LNG or SNG became available. IPAC explained that if SNG or LNG projects captured and penetrated United States markets, the necessity to operate them at full load factors might make it difficult for Canadian surplus gas to penetrate these markets.

IPAC filed a formal cost-benefit analysis prepared by Canadian Resourcecon Ltd. to illustrate the benefits to Canada of exporting a projected surplus of western Canadian production over the period 1979-1998.

Resourcecon calculated the net present value of the exported surplus to be $10.4 billion (1978 dollars) or $0.67/Mcf, using a 10 percent discount rate. Resourcecon based the calculations on a projected surplus of 15.5 Tcf which it obtained from its estimate of future Canadian requirements and IPAC deliverability estimates. Resourcecon believed, however, that the net benefit of $0.67/Mcf would be essentially the same if IPAC's surplus of 12 Tcf over the same period were assumed.

Manitoba and the Inuit Tapirisat stated that Resourcecon's analysis failed to consider adequately all of the costs experienced by Canadians in future years as a result of near-term exports. It was also Manitoba's position that the benefits and costs should be discounted in real terms at a rate of two percent per annum because it believed this lower rate of discount was more appropriate to evaluate costs and benefits for energy projects.

IGUA

IGUA stated that, because of the positive effect that cash flows generated by exports could have on exploration, the most favourable view possible should be given to the export of gas additional to presently authorized commitments, subject to the primacy of Canadian requirements.

IGUA held that incentives should be given to the gas industry to develop future reserves for domestic consumption and export. IGUA argued that it was possible that through such incentives proven reserves would be found such that deliverability from these reserves would be substantially in excess of Canada's perceived requirements leading to the possibility that these might be more economical to develop than heavy oil and tar sands.

IGUA provided no specific export formula but did suggest a protection period of 20 years of Canadian requirements. IGUA suggested that an exportable surplus be evaluated by considering a range of demand estimates and reserves/deliverability estimates. IGUA held that when a surplus appeared to be available based upon the lower estimate of reserves and the upper estimate of requirements, there would be grounds to consider further exports. These would be subject to reduction if new information indicated a deterioration in the amount of the deemed surplus or if deliverability were to fall below some limit, such as meeting the forecast five years' requirements.

IGUA suggested that if surpluses appeared only when lower than maximum requirements were considered or when higher than the minimum reserves were considered then exports might be granted for somewhat shorter periods. In IGUA's view, such exports might be made more compatible with the protection of Canadian requirements through the application of swap arrangements.

IGUA stated that there was need for flexibility in the procedures for determining whether there were reserves of gas in Canada surplus to Canada's reasonably foreseeable requirements, taking into account deliverability considerations. IGUA argued that such procedures should recognize the longer-term unreliability of any rigid determination of surplus by allowing short-term exports and export renewals. IGUA also suggested, in the context of flexibility, that the surplus be determined annually and if it were necessary at any time to curtail exports, that the production cut-back be fairly distributed amongst the producers in order to maintain exploration incentives.

Inland

With regard to exports of natural gas from British Columbia, Inland supported a position taken by the British Columbia Energy Commission in its 1977 Petroleum and Natural Gas Price and Incentives Hearing Report including a recommendation that no attempt be made to export gas in addition to British Columbia's currently remaining obligation of about 2.4 Tcf.

Inland stated that in the event that a surplus to domestic needs developed, it did not disagree with short-term exports. However, Inland held that domestic natural gas prices should not be set at a level that discouraged domestic customers from using natural gas merely to provide natural gas for the export market. Inland stated further that the domestic customers should not be asked to bear the cost of creating an exportable surplus.

Inuit Tapirisat

The Inuit Tapirisat opposed the adoption of any new for mula for calculating surplus gas. The Inuit Tapirisat con cluded that Canadians were not well served by the ol 25A4 formula, and held that Canadians would not be we served by any replacement formula.

With respect to natural gas supply and demand, the Inu Tapirisat argued that in the long term, there could be n surplus of natural gas. Furthermore, it stated that Canadi ans would not need High Arctic natural gas to meet do mestic and export commitments if they adopted a sensi ble approach to conserving and managing their non renewable reserves of natural gas from other areas. Wit respect to long-term energy forecasts, the Inuit Tapirisa rejected the notion that the Board should formulate polic regarding the export of so-called "surplus" gas on th basis of long-term forecasts and stated that particularly i the long run, forecasts were simply not reliable enough t serve as a basis for formulating export policy.

The Inuit Tapirisat declared that the Inuit were not pre pared to pay the cost of cultural dislocation for the sake c shipping so-called "surplus" natural gas resources out c the country.

Manitoba

Manitoba stated that the 25A4 formula was inadequate and that supply forecasts should be based on deliverabi ity calculations rather than reserves. Manitoba recom mended that short-term increases in deliverability be dis tinguished from a "surplus". Manitoba also supported th Board's previous finding that frontier reserves not be ir cluded as part of the available supply until there was a approved means of transmitting them to markets.

In respect of protecting domestic requirements, Manitob recommended using a 30-year period of protection. As principle, to determine an exportable surplus Manitob suggested relying on the sum of deliverabilities less cur rent export licence volumes and less a reasonable fore cast of domestic requirements over the next 30 years.

Manitoba recommended that periodic public hearings b held for the determination of surplus where policy option could be aired and evaluated, rather than focusing upo a formula as an approach to defining surplus. Manitob stated that the holding of public hearings would provid flexibility to more closely account for changes in the sup ply situation, consumption patterns and their relationshi to future natural gas prices, which was an unknow variable.

Manitoba submitted that the need for cash flow for exploration and development must not supersede the need for continuing protection of long-term domestic requirements.

Midwestern

Midwestern submitted that in determining the volume of gas available for export, the Board should not only first provide for the continued export of natural gas under existing export licences but should also give preference to the authorization of additional exports as necessary to extend the terms of existing export licences.

Describing its transmission system, Midwestern explained that in many cases the Canadian gas sold to and through Midwestern was the sole source of natural gas available to its customers. Midwestern concluded that if gas export Licence No. GL-1 were not renewed or such supply were not provided for, approximately two-thirds of the total supply to Midwestern's customers in Minnesota and Wisconsin would be terminated and curtailments would be necessary with a result that only 50 percent of Priority 1 (residential and small commercial) loads could be served. Midwestern stated that there was no other supply of natural gas for these customers and the remaining time period of existing licences might not be adequate for them to convert to alternative fuels.

Mobil

Mobil stated that there was currently a natural gas surplus and declared that it strongly supported efforts to expand domestic and export markets. Mobil held that increased demand would spur continued reserves development. Mobil argued that gas market expansion offered a significant opportunity to favourably affect Canada's balance of payments.

Niagara

Niagara was of the view that there were three general categories of export markets:

a) those which had been developed with, and were entirely dependent upon Canadian gas and had no alternative source of supply within economic reach;

b) those which were now served by Canadian gas but were not entirely dependent thereon and did have an alternative source of supply; and

c) those which were proposed for surplus Canadian gas.

Niagara advocated that Canada adopt an export policy whereby exports were allocated first to category 1) markets and then to category 2) markets and finally to category 3) markets if volumes permitted.

Norcen

Norcen submitted that a structured gas surplus calculation procedure would not be of much value at the present time. For a formula to be worthwhile, reliable projections of both supply and demand were required; however, Norcen argued that there were major uncertainties with respect to both these factors.

Using its base case demand scenario, Norcen contended that short-term exports were justifiable as long as they were conditioned so that Canadian requirements for gas would be met on a day-to-day basis.

Norcen suggested that the best option for dealing with the current problem of surplus deliverability was to allow some of the gas to be exported until such time as Canadian markets developed. Furthermore, Norcen said that short-term exports would not materially affect the crossover point between supply and demand. In Norcen's base case, demand without additional markets first exceeded supply in 1997 and after making provision for additional markets, in 1999.

Norcen submitted that exports would provide the required cash flow for further exploration while the Canadian market was expanding. Norcen estimated that continued exploration momentum resulting from export revenues received would produce up to 250 Bcf of additional annual deliverability by 1995.

Norcen stated that a high level of exploration would allow for a faster delineation of the western Canadian resource base and contended that the evaluation of sparsely explored areas was necessary to determine when frontier resources might be required.

Norcen pointed out that gas exports, particularly if transported by existing pipelines, would improve Canada's balance of payments.

NCGas

NCGas recommended the adoption of a formula for determining surplus natural gas deliverability, and supported the export of such a surplus.

NCGas stated that deliverability from proven reserves

(which were presently connected or could be connected within five years at reasonable rates of deliverability) at a level equal to the fifth year's forecast requirements should be reserved for Canadian market use and that any and all deliverability in excess of this level could be exported for whatever term the deliverability from proven reserves was projected to exceed the fifth year's demand.

NCGas proposed that priority should be given to the extension of existing licences. NCGas stated that once new or renewed exports are licenced, they could be honoured without undue burden on Canadians and without the need for an annual review and surplus determination.

NCGas stated that its program would give Canadians sufficient protection to enable the projected demand to be developed and contracted for by Canadian consumers and by Canadian utilities. NCGas submitted that this proposal would encourage the expansion of Canada's natural gas reserves and the deliverability of these reserves. NCGas pointed out that this program gave adequate notice of future shortages with sufficient lead time to enable frontier pipeline projects to be initiated.

Ontario

Ontario stated that natural gas exports under existing contracts should continue to be honoured and any supply shortfall should be shared with domestic customers on a pro rata basis. Ontario argued that a short-term increase in the deliverability of natural gas must not be defined as a surplus. Ontario held that the long-term national interest of ensuring secure supplies of gas should not be prejudiced by the purported short-term cash flow problem of the industry and that additional exports should be considered only after Canada's future needs had been assured. Ontario also argued that until frontier reserves became available to domestic markets, they must not be included in the energy supply forecasts in order to justify exports.

Ontario suggested a surplus determination procedure which would require, before a surplus was found to exist, that deliverability meet or exceed Canadian natural gas requirements on a year-by-year basis for each of the next ten years. Furthermore, reserves of natural gas would be set aside equal to the total forecast requirements over the next ten years plus 15 times the level of forecast requirements in the tenth year.

Pan-Alberta

Pan-Alberta recommended that in the determination of an exportable surplus the Board should consider factors other than just supply and demand. Pan-Alberta held th deliverability estimates should not be a restrictive facto Pan-Alberta argued that the Board should take into co sideration continued exploration and the delineation new reserves and also made the point that the Boa should assess demand projections conservatively. Pa Alberta also stated that any procedure must be flexib and should not be restricted by a mathematical typ formula.

With regard to supply, Pan-Alberta submitted that th Board should take into account at least a portion of thos reserves which have been identified in frontier area Pan-Alberta stated that maintenance of a high level of a tivity in the producer segment of the industry was the ke to ensuring adequate supplies. Pan-Alberta strongly re ommended that the Board, in its assessment of natur gas supply and deliverability, consider the vital impo tance that an equitable return to the explorer, and th availability of markets within a reasonable time fram played in the delineation of new reserves and the avail bility of deliverability.

Sproule Associates, acting as consultants to Pan-Albert concluded that future Canadian requirements could rea sonably and realistically be protected by setting aside r serves equal to 15 times the projected annual consum tion in the first calendar year after the year of the hearir to consider an export application. Sproule Associate added that deliverability should not be used in the surplu formula to protect Canadian requirements, as it was un kely that a realistic forecast of deliverability could be pr pared and as deliverability from Canadian reserves shou be increasing for some time in the future.

Sproule Associates held that established frontier reserve that could realistically be considered to be available supply markets during the forecast period should be i cluded in the determination of surplus.

Panarctic

Panarctic argued that the term of export contracts cou be shortened to the advantage of Canada while still pe mitting the financing of incremental pipeline facilities Canada and the United States. Panarctic said that incr mental facilities in the United States could be finance with a five to six year primary term at full export volume plus a five to six year secondary term, with volumes d clining to zero. Panarctic suggested that licences be i sued as above and pointed out that although licence would be restricted to two six year terms, it would still b

reasonable for a United States purchaser to commit to take gas for up to 20 years, in the event that Canada wished to make the gas available after the expiry of the initial licences. This commitment would assure the financing of incremental facilities in Canada. The uncommitted reserves would be available for use in Canada. Thus, by committing to export 25 to 45 percent of the initial reserves required to support a marketing prospect, the balance of the gas which otherwise would not have been available for Canada, could be made available domestically.

Panarctic stated that export volumes in the secondary term should be renewed annually on recommendation of the Board, depending upon exportable surpluses from time to time.

PanCanadian

PanCanadian submitted that surplus determinations should be based on best estimates of production from non-frontier supplies and requirements plus authorized exports as determined by industry, government, public interest groups and the NEB. PanCanadian held that the NEB should determine a specific surplus volume that could be authorized for export over a specific time period. PanCanadian suggested authorizing at least 300 Bcf/year for the next five years, a term that could be extended over the next decade as conditions warranted.

PanCanadian argued that additional exports would contribute significantly to improving Canada's balance of payments and stated as an example that additional exports of 300 Bcf/year would earn receipts of $720 million at today's price and exchange rate.

PanCanadian pointed out that unless new markets for natural gas were found in the immediate future, the level of exploration and development in Canada would decline. On the other hand, it stated that additional exports would provide incentives to continue exploration in the frontier and higher risk non-frontier areas. PanCanadian said that successful exploration and development would result in larger amounts of proved reserves and increasing confidence in reaching the estimated ultimate potential.

PanCanadian added that sustaining the current levels of exploration and development would maintain the petroleum industry and its service industries with attendant multiplier effects on the national economy.

PanCanadian stated that the United States market was now open to Canadian gas exports but cautioned that the period of access could be limited.

Polar Gas

Polar Gas did not submit a new formula or procedure, but made several recommendations as to desirable characteristics of any modifications to 25A4. Polar Gas submitted that forecast demand in the current year should be used for the surplus calculations and multiplied by some factor which the Board considered appropriate. Established reserves would then be compared with total requirements as calculated.

In determining whether a surplus is available for export, Polar Gas submitted that frontier gas reserves should not be taken into account except as part of facilities applications.

Polar Gas suggested that adequate reserves should exist to provide a forecast deliverability for a fixed initial period of proposed export licences. Polar Gas recommended that forecast deliverability from established marketable reserves and expected additions to supply should meet forecast domestic requirements for the initial period plus existing and applied-for exports for the initial period or until the expiry of the terms of their licences, whichever was less.

Polar Gas recommended the holding of regular periodic reviews, at intervals of not less than three years, to consider domestic and export requirements and deliverability of established marketable reserves and expected additions. If there were insufficient deliverability to meet domestic requirements and previously licensed exports, Polar Gas' recommendation was to institute shared curtailment of supplies between the domestic and export markets on a pro rata basis.

ProGas

ProGas presented a forecast of Canadian natural gas supply and requirements but no specific export formula or procedure was discussed.

ProGas estimated that there would be a surplus of 6.5 Tcf from conventional sources in western Canada through the period to 1995.

ProGas stated that it was offering to purchase approximately 500 MMcfd of Alberta gas under long-term contracts and proposed to market such gas in the long-term in Canada with short-term sales to the United States Midwest.

Quasar

Quasar submitted that there was a surplus of natural gas in Canada and stated that the market for gas had to be expanded if there was to be ongoing exploration and development activity. Quasar recommended that the most expeditious way to expand the market for Canadian gas would be to authorize additional exports to the United States.

Quasar argued that exploration in the frontier areas would occur if companies were assured that a ready or foreseeable market existed and that the market would provide prices which would give a fair return on money invested.

Quebec

Quebec stated that it was in agreement with the Board's 1975 Gas Report with respect to the desirable characteristics of a method of determining a natural gas surplus.

Quebec advocated calculating any surplus on the basis of total Canadian energy consumption as forecast for the next 25 years, the natural gas requirements being defined as being 30 percent of total energy demand. Furthermore, Quebec recommended that any determination, rather than relying solely on reserves, should take into consideration potential deliverability.

Quebec added that the formula should be applied with sufficient flexibility to allow special circumstances to be taken into account such as sudden changes in supply and demand, or overall negotiations with the United States for the purpose of resolving the problem of a more stable market for Canadian heavy oil. Quebec recommended that the federal government negotiate with the United States to gain access to the United States market for Canadian heavy fuel oil, and suggested that future exports of natural gas could be used as a lever in these negotiations.

Saskatchewan

Saskatchewan maintained that the first priority of Canadian decision-makers, with respect to establishing export commitments, should be to ensure that Canadian consumers of natural gas would not be unduly penalized economically or in other ways in the future because a decision was made to export gas during a period when there was a short-term excess of supply.

Saskatchewan recognized that short-term exports from the "gas bubble" would achieve economic gains for Canadians, but argued that there were long-term social and economic benefits from ensuring that a secure supply (gas could be delivered to Canadian consumers for an ap propriate period of time in the future.

Saskatchewan submitted that a supply of natural gas su ficient to meet reasonably foreseeable Canadian requir ments plus existing authorized exports should be ensure before consideration was given to additional exports. determining to what extent, if any, an exportable surplu existed, Saskatchewan recommended that certain princ ples be adhered to. The first principle was to ensure th enough gas could be delivered from established reserv to meet forecast Canadian requirements over a ten-ye period. Secondly, Saskatchewan suggested that th Board determine gas surpluses on the basis of deliverab ity rather than reserves. Saskatchewan recommende against including inaccessible supplies in determinir whether or not there was an exportable surplus and a gued that only existing reserves should be included in th surplus calculation. Saskatchewan suggested that th Board determine gas surpluses on the basis of deliverab ity from reserves considered to be recoverable with a hi degree of certainty.

SPC

SPC supported the Board's opinion that a procedure f determining exportable surpluses should incorporate g deliverability rather than reserves in supply consi erations.

Shell

Shell stated that the 25A4 formula was inadequate b cause it set aside an excessive quantity of reserves. Sh argued that gas deliverability should be the key criteri in assessing any exportable surplus.

To determine whether a quantity of gas for which an e port licence was sought was surplus to domestic requir ments, Shell proposed two tests: a test of maximum a nual export volume and a ten-year deliverability test.

Shell's first test was: $E = (D_4 - R_4)\frac{t}{25}$

where E = maximum annual export volume.

D_4 = deliverability in the fourth year.

R_4 = domestic requirement in the fourth year, as would be if no conservation had occurred su sequent to 1978, plus currently authorized e port volumes in the fourth year.

t = number of years until deliverability is exceeded by domestic requirements and currently authorized exports.

Shell's second test was that domestic requirements plus currently authorized exports plus requested exports should not exceed deliverability for at least ten years.

Shell recommended that new export licences be restricted to five or six years so as to minimize the adverse effect of forecasting errors or a major unforeseen change in either supply or demand trends.

Shell estimated current deliverability of gas in established areas to be about 3200 Bcf/year which exceeded current domestic market demand and authorized exports by about 430 Bcf/year or 16 percent. Shell's methodology determined that approximately three Tcf of gas were surplus and available for export.

Shell stated that incremental exports would stimulate exploration activity and would lead to better supply and deliverability protection than the alternative of reduced exploration activity and gas surplus under constrained market conditions. Furthermore, Shell estimated that 300 Bcf/year of exports would generate $700 million in revenue, impacting positively on the Canadian balance of payments.

TransCanada

TransCanada submitted that there should be both a reserves test and a deliverability test to determine whether an exportable surplus existed. The exportable volumes would be the lesser of the volumes resulting from application of the two tests.

As its reserves test, TransCanada proposed a 25A2 formula. As regards its deliverability test, TransCanada submitted that deliverability would have to exceed projected total domestic demand plus authorized exports in each of the ten years following the date of the new export licence applied for. In this test, existing licences due to expire should be assumed to have been extended to the end of the ten-year forecast period. TransCanada recommended that 50 percent of trend gas be included, on a conservative basis, as part of deliverable supplies. TransCanada suggested that approvals be for periods shorter than ten years, but also pointed out that frontier-based projects could require longer licence terms.

TransCanada held that frontier natural gas reserves should not be considered in the determination of an exportable surplus until viable transportation systems had been approved by regulatory bodies and financing arrangements established.

TransCanada proposed that new licences include as a condition that the licensees be required to submit, on an annual basis, or such other period as the Board deemed necessary, up-dated assessments of deliverability from the licensees' own reserves. TransCanada also recommended that all companies subject to the Board's jurisdiction be required to file, on an annual basis, their updated assessments of deliverability from their own reserves for at least the next ten years. Upon reviewing these assessments, and following a public hearing, TransCanada argued that the Board could order a reduction or termination of the volumes authorized for export under new and extended licences, and added that one year's notice of reductions or terminations would be desirable.

With regard to reserving for Canadians any benefits from conservation restraints in Canadian demand, TransCanada stated that additional revenues resulting from exported surpluses partially created by conservation efforts could be of long-term benefit to Canadians in that such revenues would be used to explore for and develop reserves. TransCanada said that additional exports would improve Canada's balance of payments.

Union Gas

Union Gas did not address directly the questions of an exportable surplus or increased exports to the United States. It argued that the federal government should clearly endorse and encourage greater use of natural gas, first in established markets and then in new markets.

Union Gas recommended that reports indicating the relatively favourable supply situation for natural gas in Canada should be monitored and, where possible, confirmed by the Board. It believed the public should be kept aware of the situation.

Union Gas argued against adopting a policy of importing large quantities of oil and offsetting the cost by exporting large quantities of gas, and held that such an approach overlooked the uncertainty of the supply of international oil.

Universal

Universal argued that without a market for some portion of its shut-in reserves, it would be unable to obtain additional financing and, therefore, would have to further curtail its exploration and development program.

In addition to supporting domestic market expansion, Universal supported some short-term exports of natural gas which was surplus to Canadian needs, and stated that such exports would provide the impetus for development of reserves for the Canadian market.

Westcoast

Westcoast proposed that a two-step test be used to determine any surplus to domestic requirements. First, Westcoast suggested a conservative test, which would provide protection on a maximum day and annual basis for 20 years by comparing a conservative estimate of gas production with the most likely estimate of gas requirements including then authorized export volumes. Any resulting surplus would be available for export on a guaranteed basis, barring any major disruption on the Canadian energy scene, for 10 to 12 years in order to make new projects economically viable. In its second step, Westcoast suggested that for the 20-year forecast period, the most likely estimate of gas production be compared with the most likely forecast of requirements including then authorized exports, plus any additional volumes authorized for export by Westcoast's first test. Westcoast suggested that any surplus thus determined should be available for export on a "best-efforts" basis only, and authorized for five-year terms.

Westcoast pointed out that one difficulty that any procedure for determining a surplus would have was the need to recognize the economics of gas production and marketing. Westcoast stated that since deliverability was directly related to the economics of gas production, an apparent surplus could quickly evaporate if the economics of production were altered dramatically. Westcoast commented that requirements too, were subject to price and other incentives and disincentives to use gas. Westcoast stated that government policy could exert omnipotent influence on the economics of gas production and marketing and concluded that any determination of a volume surplus to Canadian requirements would have to include guidelines outlining the basic economic parameters inherent in such a calculation.

Westcoast further submitted that a direct relationship between reserves and deliverability could exist with proper incentives. Westcoast stated that if deliverability appeared inadequate to support exports, the Board should then examine whether reserves were surplus to Canada's 20-year requirements, and if so, should determine what incentives were required to increase deliverability from these reserves.

Views of the Board

The determination of what constitutes a "surplus" of na ural gas has been a fundamental issue that the Board ha had to deal with since its inception. As circumstances re lating to the exploration, development and marketing (natural gas have changed, the Board necessarily has ha to review, from time to time, its approach to the determ nation of the natural gas surplus and the regulation of na ural gas exports.

The matter of the determination of surplus gas within th meaning of Section 83 of the National Energy Board Ac was a subject of the inquiry held by the Board in 1974-75 In the Board's 1975 Gas Report, it stated, "The Board ir vited an evaluation of the gas surplus calculation proce dures developed and applied to assess export applica tions during the period of rapid growth of the natural ga industry......It now appears that more weight should hav been given to deliverability as distinguished from re serves". It stated further that "any procedure envisage (for determining surplus) should have as many of the fo lowing characteristics as possible:

- It should be easily understood and applied.
- It should incorporate gas deliverability rather than re serves in the supply considerations.
- It should be flexible to respond to changin circumstances.
- It should provide continuing protection for Canadian de mand throughout any period of export.
- It should provide incentive and encouragement to th gas industry.
- Licensed export commitments should be satisfied to th extent possible.
- It should reserve for Canadians any benefits from cor servation restraints undertaken by Canadians."

The Board, in the report, recognized that at that tim there was no apparent surplus and stated that beyon stating the above general principles, it intended to defe the development of a structured gas surplus calculatio procedure until it could reasonably be expected to b required.

For the present inquiry the Board again asked for views (

submittors on a surplus determination procedure and referred submittors to the views of the Board expressed in its 1975 Gas Report, as summarized above.

A wide variety of suggested formulae for determining surplus was put forward by submittors, some employing a reserves test, some employing a deliverability test and several employing both. A few of the formulae would increase the level of long-term protection afforded by the 25A4 formula previously used by the Board. Many of the submittors believed it more important to ensure that short-term deliverability requirements of Canadian markets and existing export markets be met before authorizing additional exports. Most submittors believed that future licences should be for short terms but that there should be flexibility in the Board's procedures to allow longer-term licences where it could be demonstrated that such would be in the public interest. Many indicated that future licences should provide for reduction of the authorized export volumes if, due to unforeseen circumstances, the Board found that the gas was needed to meet Canadian requirements.

After reviewing its conclusions in the 1975 Gas Report and after carefully considering the views of submittors at this inquiry, the Board concludes that the procedure for the determination of the surplus of natural gas remaining after making due allowance for Canadian requirements and for authorized exports should rely both on deliverability tests, and on a reserves test.

The Board proposes to employ three tests in determining whether or not a quantity of gas proposed to be exported is surplus to the reasonably foreseeable requirements for use in Canada. These tests, the Current Deliverability Test, the Current Reserves Test and the Future Deliverability Test, are described in detail hereunder.

Current Deliverability Test

The potentially large economic dislocations that could result from unanticipated shortfalls in natural gas deliverability make it imperative that there be a high degree of confidence that deliverability will meet annual Canadian requirements in the immediate future. Such confidence is also necessary to meet the planning requirements of gas distributors. The difficulties that unanticipated reductions in authorized exports would cause export customers make it important to provide similar protection for authorized exports. The Board believes that a test utilizing deliverability from established reserves will provide the requisite high degree of assurance.

Procedure

Under this test it would be necessary to demonstrate a surplus of annual deliverability from established reserves in excess of the sum of total annual Canadian requirements and authorized exports for a minimum period of highly assured protection. This test would be used to determine the upper limit of the maximum annual quantities that might be surplus during this period of highly assured protection i.e., it would determine the "shape" of the available surplus in terms of annual rates. At present the Board believes this period of highly assured protection should be a minimum of five years.

Current Reserves Test

Tests solely relying on deliverability could lead to excessive industry activity to increase deliverability at the expense of developing new reserves. Therefore the Board believes that a reserves test is necessary to maintain a reasonable relationship between established reserves and deliverability.

A test utilizing remaining established reserves compared with 25 times projected demand four years in the future introduces the uncertainty of a future projection on the demand side but not on the supply side. A formula based on the current year's demand would be more appropriate and a suitable amount of protection would be afforded by setting aside established reserves to provide coverage of current Canadian demand for a period of 25 years plus authorized exports.

Procedure

The Current Reserves Test will determine the quantities of established reserves which remain after setting aside 25 times the current year's Canadian demand, plus authorized exports. Licences for the export of gas could be granted for a total quantity which did not exceed the maximum total quantity determined to be surplus by the Reserves Test and within the limits established by the Deliverability Tests.

Future Deliverability Test

The Board believes it is important not only to ensure that requirements be afforded the highly assured protection from established reserves as provided under the Current Deliverability Test but also that a longer period of surplus be foreseen when measuring requirements against forecast deliverability from a combination of established reserves, reserves additions and, when appropriate, new sources of gas such as frontier reserves. It would be nec-

essary, in considering proposed new exports which could meet the Current Deliverability Test and the Current Reserves Test, to ensure that such exports would not result in deficiencies in the longer protection period.

On the other hand, if the trend of future reserves additions is expected to provide surplus annual deliverability beyond the period of highly assured protection, it may be in the public interest for the Board to grant longer term export licences that include deliverability from trend gas, provided the Current Reserves Test can be met. It might be appropriate to grant such longer term licences to make a new project, such as a major transmission system, economically viable.

An assessment of the annual deliverability protection for Canadian consumers for a longer term requires a comparison of forecast demand and authorized exports with expected deliverability, including deliverability from established reserves, reserves additions and when appropriate, expected new sources such as frontier gas.

Procedure

Under this test annual quantities of gas could be deemed to be surplus if the forecast deliverability from established reserves, reserves additions etc., exceeded expected Canadian demand plus authorized exports for a reasonably foreseeable period. At present the Board believes this period of future deliverability protection should be some ten years.

This test would have two functions. First, it would be used to ensure that any proposed exports, which might otherwise be authorized on the basis of satisfying the first two surplus tests, would not cause a future deliverability shortfall within a ten-year period. Secondly, in any case where the Board finds that it would be in the public interest to grant a licence term in excess of that indicated by deliverability from established reserves, the extended portion of the licence, both with respect to annual quantities and term would be limited by the projected deliverability from future reserves. All exports under this extended portion of the licence would be subject to reduction, if subsequent deliverability determinations indicated a deficiency within the extended term.

Characteristics of the Board's Protection Procedure

The Board believes these tests generally encompass the characteristics set out in the 1975 Gas Report. However, in light of the evidence presented, the Board, in reviewing the 1975 recommendation with respect to conservation "savings", now concludes that because of the anticipated shorter terms of future export authorizations under the proposed protection procedure, specific provision for protection of conservation savings is not required.

The Board does not agree with those submittors who proposed that some form of automatic extension of existing licences be accounted for in the surplus determination procedure. Licensees who wish to export natural gas beyond the terms of their present licences must apply for authorizations in the same manner as any other applicants for licences to export gas.

With regard to the treatment of new exports, future exports authorized on the basis of deliverability from established reserves (i.e. within the highly assured protection period) would have the same status, in regard to interruptibility, as currently authorized exports. That portion of any export authorization extending beyond the period of highly assured protection would, however, be conditional upon sufficient deliverability being developed to meet expected Canadian requirements and authorized exports in each year of the extended term of the licence.

An issue that was raised by various submittors was the timing of the inclusion of frontier natural gas reserves, or deliverability from these reserves, in the calculation of the natural gas surplus. The Board considers that established frontier natural gas reserves, trend additions to these reserves and deliverability from these reserves, should be included in the Board's calculations of surplus under the Reserves and Deliverability Tests only at such time as they are believed to be within economic reach. As indicated in the Chapter dealing with supply, the Board does not believe it to be appropriate to include such reserves until the Board has granted a certificate and is satisfied that the transportation facilities will be constructed. At the present time, none of the frontier reserves meets this criterion.

CALCULATIONS AND ILLUSTRATIVE EXAMPLES

Introduction

Under the Board's new protection procedure, it is not possible to state a specific volume of gas which is surplus to the reasonably foreseeable Canadian requirements under all circumstances. It would be necessary to apply all three tests to determine if a proposed export volume was surplus and limitations may be imposed by one or more of the tests.

To illustrate the use of the Board's tests, three examples have been included. These show how the annual quantities and term of a proposed export may be limited by the

Current and Future Deliverability Tests in addition to the total volumetric limitations which may be imposed by the Current Reserves Test.

While provision has been made in the Board's Current Reserves Test for protection of 30 times Alberta's current requirements, consistent with AERCB's reserves protection procedure, no provision has been made in the Board's Deliverability Tests for any limitations which may result from application of AERCB's protection formula. As pointed out in the Board's Northern Pipelines Report, a rigid application of the current Alberta policy could result in additional restrictions being applied to volumes available for export. However, that policy is the subject of a hearing which has been called by AERCB commencing on 13 February 1979 and it will therefore be subject to review.

Current Deliverability Test

The first step in the application of the Current Deliverability Test is to forecast deliverability from established reserves assuming deliverability is kept equal to domestic demand plus currently authorized exports for as long as

Table 5–1

CURRENT DELIVERABILITY TEST
(Bcf/yr @ 1000 Btu/cf)

	DEMAND			SUPPLY[1]				
						Tracking [2]		
Year	Domestic	Export	Total	Capability	No New Export	Case 1[3]	Case 2[4]	Case 3[5]
1979	1870	1132	3002	3533	3003	3003	3003	3003
1980	1960	1087	3047	3677	3047	3247	3547	3447
1981	2033	1023	3056	3718	3056	3256	3556	3456
1982	2114	1008	3122	3604	3123	3324	3624	3323
1983	2205	962	3166	3376	3166	3367	3167	3366
1984	2300	948	3248	3176	3248	3248	3179	3227
1985	2405	926	3330	3089	3189	3173	3091	3143
1986	2650	815	3285	2930	3050	3028	2951	2991
1987	2525	693	3218	2774	2924	2877	2831	2849
1988	2592	679	3271	2603	2789	2720	2690	2700
1989	2643	547	3190	2426	2550	2479	2452	2461
1990	2697	340	3037	2233	2361	2313	2286	2296
1991	2753	196	2949	2025	2177	2126	2095	2102
1992	2835	54	2889	1879	2042	1993	1971	1979
1993	2931	46	2976	1735	1892	1843	1815	1827
1994	3015	8	3023	1499	1717	1664	1612	1622
1995	3110	6	3116	1379	1524	1466	1445	1457
1996	3196	—	3196	1259	1373	1344	1322	1338
1997	3289	—	3289	1187	1284	1255	1237	1255
1998	3388	—	3388	1113	1188	1172	1156	1175
1999	3490	—	3490	1022	1080	1076	1061	1083
2000	3597	—	3597	947	989	994	982	1003

[1]Supply is from established reserves only.
[2]Totals may not compare due to rounding.
[3]Assumes export of 200 Bcf/year for four years commencing in 1980.
[4]Assumes export of 500 Bcf/year for three years commencing in 1980.
[5]Assumes export of 400 Bcf/year for two years commencing in 1980, followed by a further 200 Bcf/year for two years.

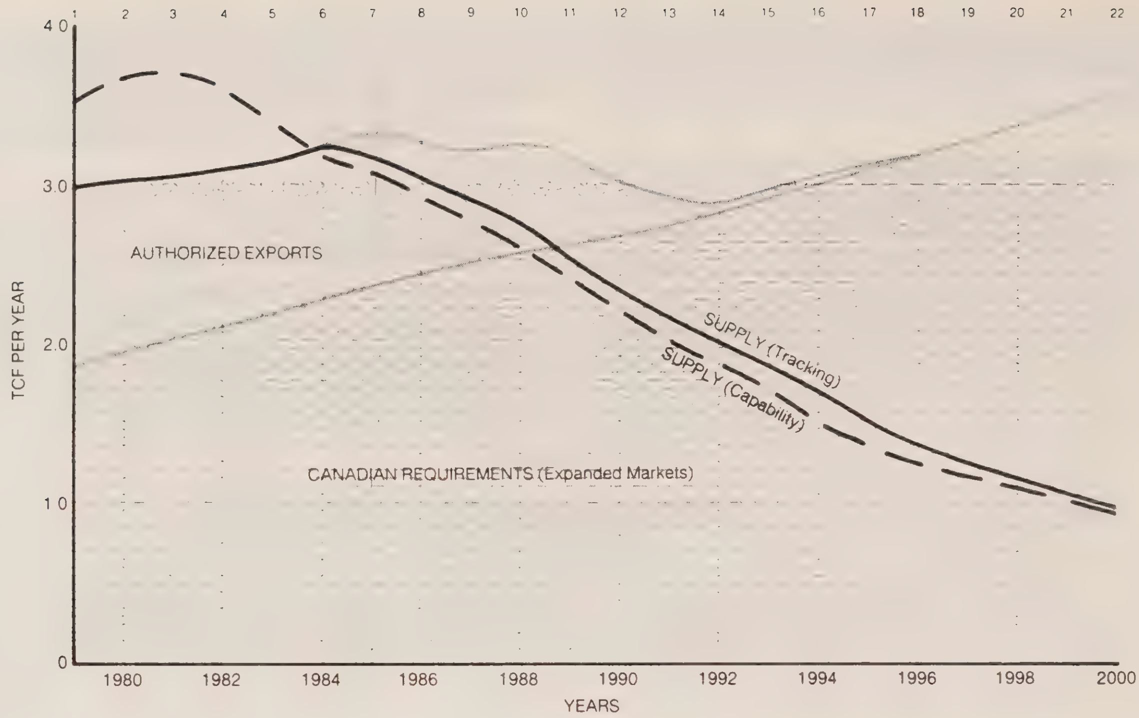


Figure 5-1 **CURRENT DELIVERABILITY TEST**
BASE CASE: CANADIAN REQUIREMENTS PLUS AUTHORIZED EXPORTS

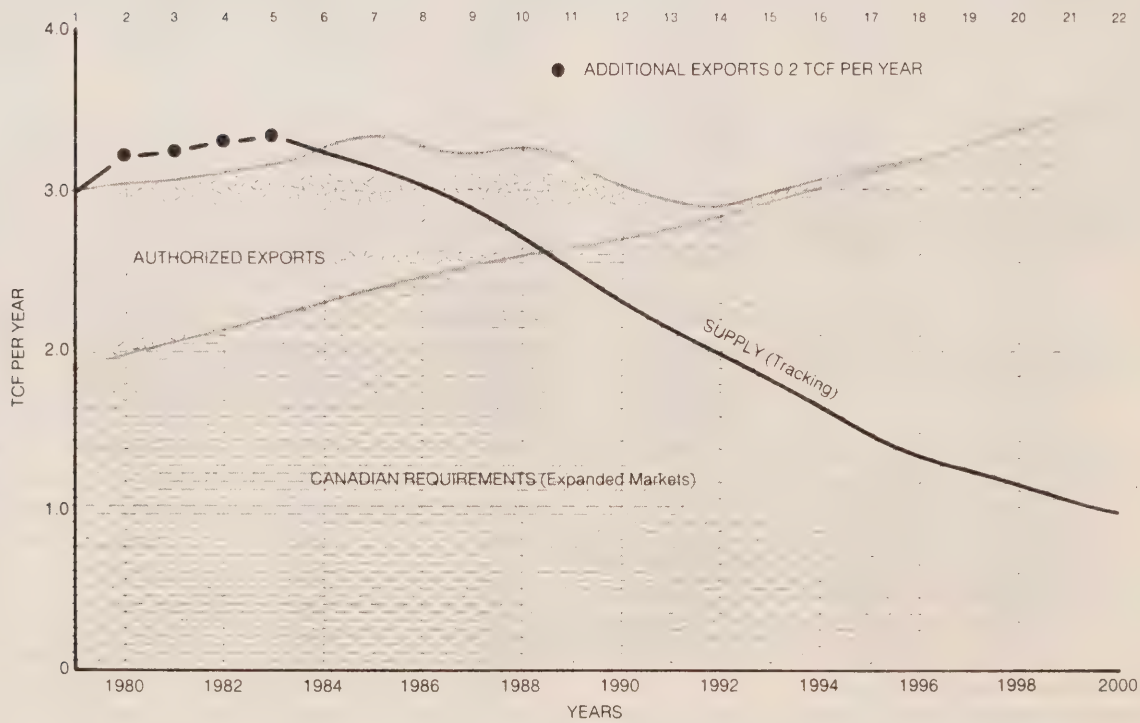


Figure 5-2 **CURRENT DELIVERABILITY TEST**
EXAMPLE CASE 1: 0.2 TCF PER YEAR ADDITIONAL EXPORTS

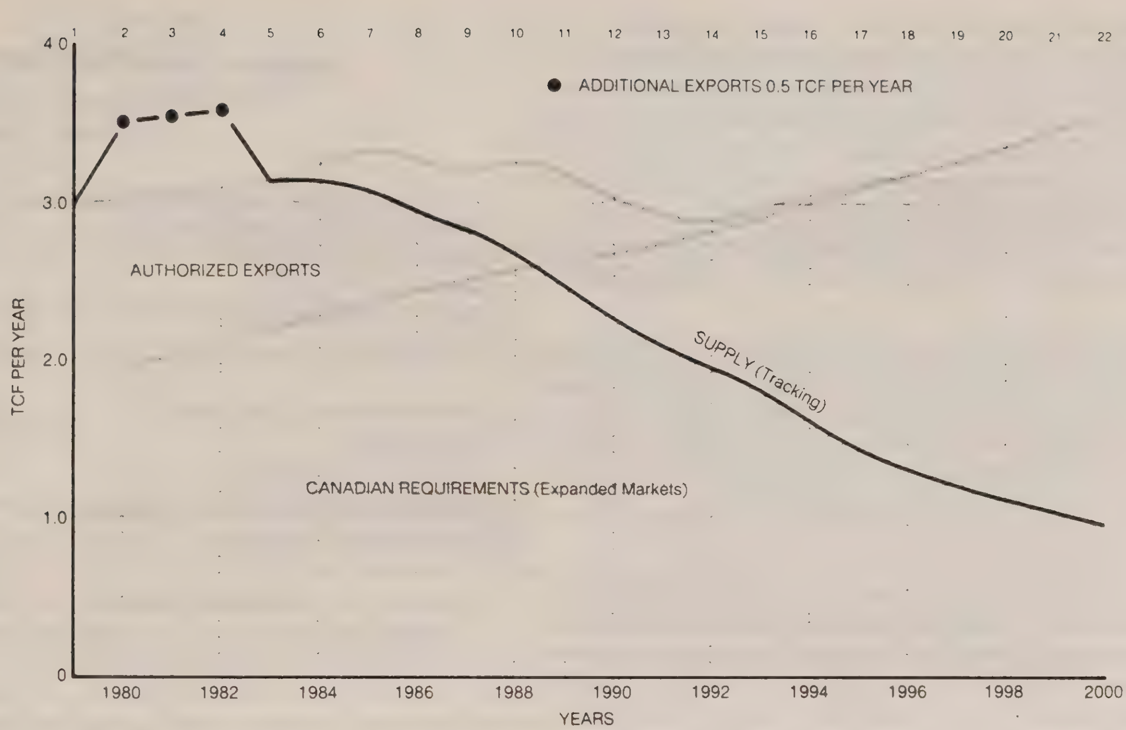


Figure 5-3 **CURRENT DELIVERABILITY TEST**
EXAMPLE CASE 2: 0.5 TCF PER YEAR ADDITIONAL EXPORTS

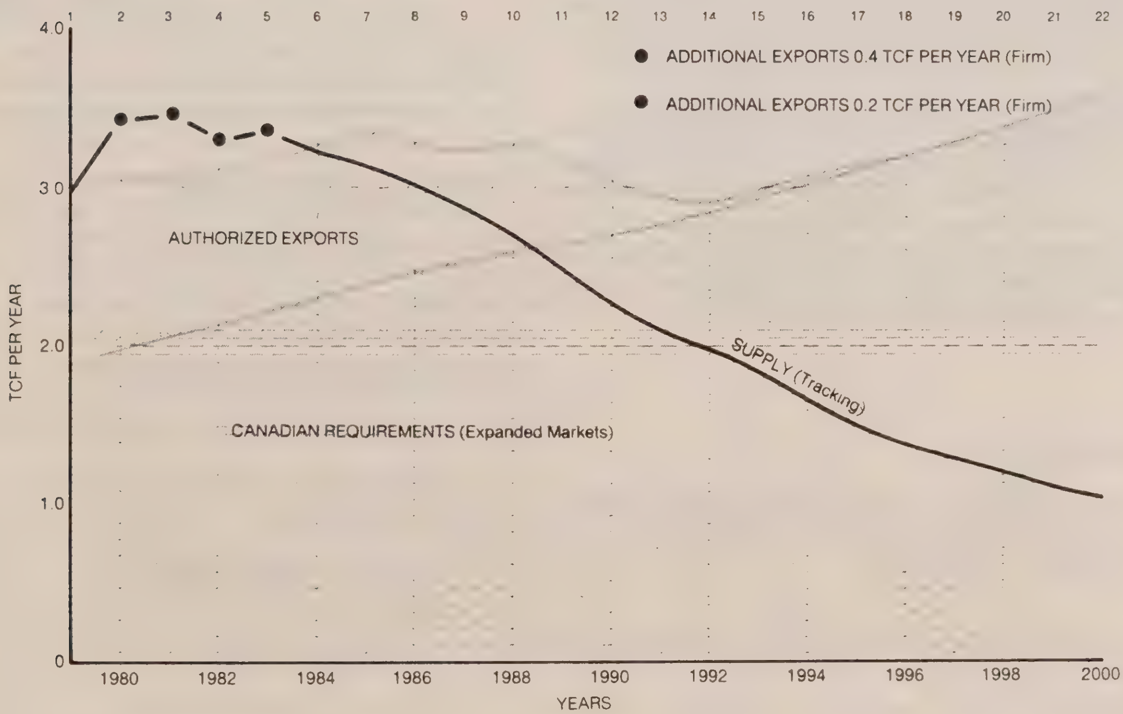


Figure 5-4 **CURRENT DELIVERABILITY TEST**
EXAMPLE CASE 3: 0.4 AND 0.2 TCF PER YEAR ADDITIONAL EXPORTS

possible and, beyond the point where deliverability can meet these needs, assuming deliverability is at maximum capability from established reserves. If deliverability cannot track, i.e. meet, demand for at least five years, then under the Current Deliverability Test there would be no surplus. At present, as shown in Table 5-1 and Figure 5-1, deliverability does track domestic demand plus authorized exports for slightly more than six years before indicating a deficiency. Hence this part of the test is satisfied.

The second step in the application of the Current Deliverability Test is to forecast deliverability from established reserves at maximum capability, unrestricted by demand. This illustrates the maximum surplus possible in each year provided this test can continue to be met. This is shown in Table 5-1 and as a dotted line in Figure 5-1.

The third step is the tracking of the annual volumes of a proposed export licence application to ensure the minimum period of protection can be met and also that the total annual requirements including the proposed export volumes can be met by current deliverability. Three examples are illustrated which satisfy these conditions. Case 1, as illustrated in Figure 5-2 and Table 5-1, is a postulated licence with an annual volume of 200 Bcf per year commencing 1 January 1980 and continuing for four years. Case 2, with an annual volume of 500 Bcf per year for three years is illustrated in Figure 5-3 and Table 5-1. Case 3, with an annual volume of 400 Bcf per year for two years, then 200 Bcf for two years, is illustrated in Figure 5-4 and Table 5-1. Any one of the exports illustrated in these cases could be authorized provided they did not violate the Current Reserves and the Future Deliverability Tests. The Case 1, Case 2 or Case 3 annual volumes would form the firm part of a licence and would be treated by the Board as having the same status as existing authorized licences in regard to interruptibility. The total firm licensable volumes in Case 1, Case 2 and Case 3 would be 800 Bcf, 1500 Bcf and 1200 Bcf respectively.

Current Reserves Test

The Current Reserves Test is calculated as of 31 December 1978 and results in a current reserve surplus of 3.8 Tcf as tabulated in Table 5-2.

This is the maximum total volume that could be licenced under the Current Reserves Test. However, under existing conditions this test is not restricting and total licenced quantities will be limited by deliverability criteria.

TABLE 5–2

CURRENT RESERVES TEST
(Tcf at 1000 Btu/cf)

	31 Dec. 1978	
Remaining Established Reserves(1)	66.1	
Less Deferred Reserves(2)	1.1	
Less B.E.R. x 1/2(3)	1.2	
Less Process Shrinkage(4)	4.6	
Total Supply		59.2
Canadian Sales Except Alberta(5)	30.0	
Alberta Sales(6)	14.5	
Authorized Export Sales(7)	10.9	
Total Requirements (including pipeline fuel)		55.4
Current Reserves Surplus		3.8

(1) Remaining established reserves; no allowance fo frontier reserves. (4.3 Tcf of reserves additions adde for 1978).

(2) Deferred reserves are those estimated to be deferre beyond 25 years. Presently the total deferred reserve in Alberta are 4.2 Tcf with 3.1 Tcf expected to be o stream within 25 years.

(3) Beyond economic reach reserves are taken as 50 pe cent of the B.E.R. reserves estimated for Alberta (2. Tcf plus that estimated for British Columbia (0.2 Tcf).

(4) Processing shrinkage is based on the expected liqu hydrocarbon removal at straddle plants.

This is calculated as follows:

Shrinkage at Empress(Tcf)	
Requirements East of Alberta (1979 Sales Plus Domestic Fuel)	1.02
Less: East of Alberta Production	0.05
Less: Empress By-Pass	0.12
Canadian Requirements Ex Empress	**0.85**
25A1 (0.852 x 25)	21.3
TCPL, ICG, Niagara Exports	2.92
Fuel for Exports	0.37
Total Flow Ex Empress	**24.6**
Total Shrinkage at Empress (24.601 x 9.2%)	2.2

Shrinkage at Edmonton	
(see page 2, Appendix 4-A; extended to year 2003)	0.695
Shrinkage at Cochrane and Waterton	
(95% of A&S Reserves of 8.317 Tcf) x 14.1%)	1.114
Shrinkage from Expansion at Empress	
(18 years at 0.0275 Tcf/yr Starting in 1986)	0.495
Total Shrinkage	**4.567**

(5) This includes pipeline fuel and losses in Canada except Alberta and is 25 times the annual demand (less Alberta) of 1.201 Tcf for 1979, but does not include fuel used in Canada for exports.

(6) This includes pipeline fuel and losses in Alberta and is 30 times the projected demand by Alberta of 0.484 Tcf for 1979, but does not include fuel used in Alberta for exports.

(7) Includes all currently authorized licenced exports plus 0.4 Tcf fuel used in Canada for export quantities.

Future Deliverability Test

This test is similar to the Current Deliverability Test except that the forecast of deliverability is based on established reserves plus forecast reserves additions. Table 5-3 and Figure 5-5 illustrate the tracking and capability forecasts of deliverability from established reserves with projected reserves additions included. The tracking case (Figure 5-5) satisfies domestic demand plus presently authorized exports for slightly more than 14 years, well in excess of the minimum requirement of ten years. However, the capability case (Figure 5-5) meets the requirement for about nine years; hence it would not be possible to export the total surplus deliverability from established reserves plus reserves additions and still meet the ten-year requirement.

The three cases which are shown illustrate how exports for 200 Bcf per year in the first case, 500 Bcf per year in the second case and 400 Bcf per year initially, changing to 200 Bcf per year in the third case, acceptable under the Current Deliverability Test, could be extended beyond the respective firm licence periods. The extended periods of the licences would be subject to having the authorized export volumes curtailed to the extent that deliverability from reserves additions became less, and/or Canadian requirements became greater, than currently forecast.

Based on the Current Deliverability Test a firm licence for four years starting 1 January 1980 at 200 Bcf per year could be authorized in Case 1. The Future Deliverability Test indicates that this licence could be extended for an additional four years at 200 Bcf per year (see Table 5-3 and Figure 5-6) and still meet the minimum criteria that domestic demand plus total exports be met for more than ten years.

In Case 2 the firm licence for three years starting 1 January 1980 at 500 Bcf per year could be extended for one year based on the Future Deliverability Test which indicates that the domestic demand plus total exports could be met for more than ten years except for a minor deficiency in the fifth year (see Table 5-3 and Figure 5-7). In Case 3 the firm licence for four years commencing 1 January 1980 at 400 Bcf per year for the first two years and 200 Bcf per year for the second two years could be extended for an additional four years at 200 Bcf per year based on the Future Deliverability Test (see Table 5-3 and Figure 5-8).

If future reviews by the Board indicated that the projected future supply/demand balance was not materializing as forecast and the protection of future requirements was less than previously predicted, the Board would have the opportunity to reduce or rescind the extended portion of the licence if the deliverability in any year during the extended portion of the licence was less then the expected Canadian demand plus authorized exports.

The total volume of firm and interruptible licensable volumes in Cases 1, 2 and 3 would be 1600 Bcf, 2000 Bcf and 2000 Bcf respectively.

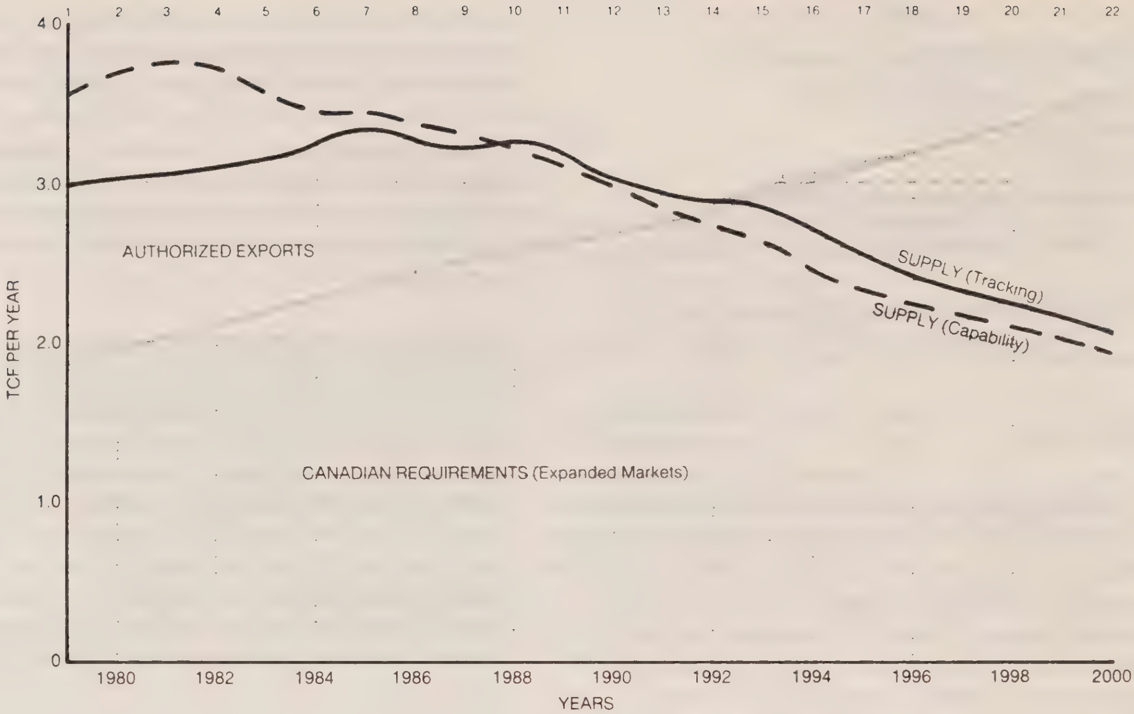


Figure 5-5 **FUTURE DELIVERABILITY TEST**
BASE CASE: CANADIAN REQUIREMENTS PLUS AUTHORIZED EXPORTS

Figure 5-6 **FUTURE DELIVERABILITY TEST**
EXAMPLE CASE 1: 0.2 TCF PER YEAR ADDITIONAL EXPORTS

Figure 5-7 **FUTURE DELIVERABILITY TEST**
EXAMPLE CASE 2: 0.5 TCF PER YEAR ADDITIONAL EXPORTS

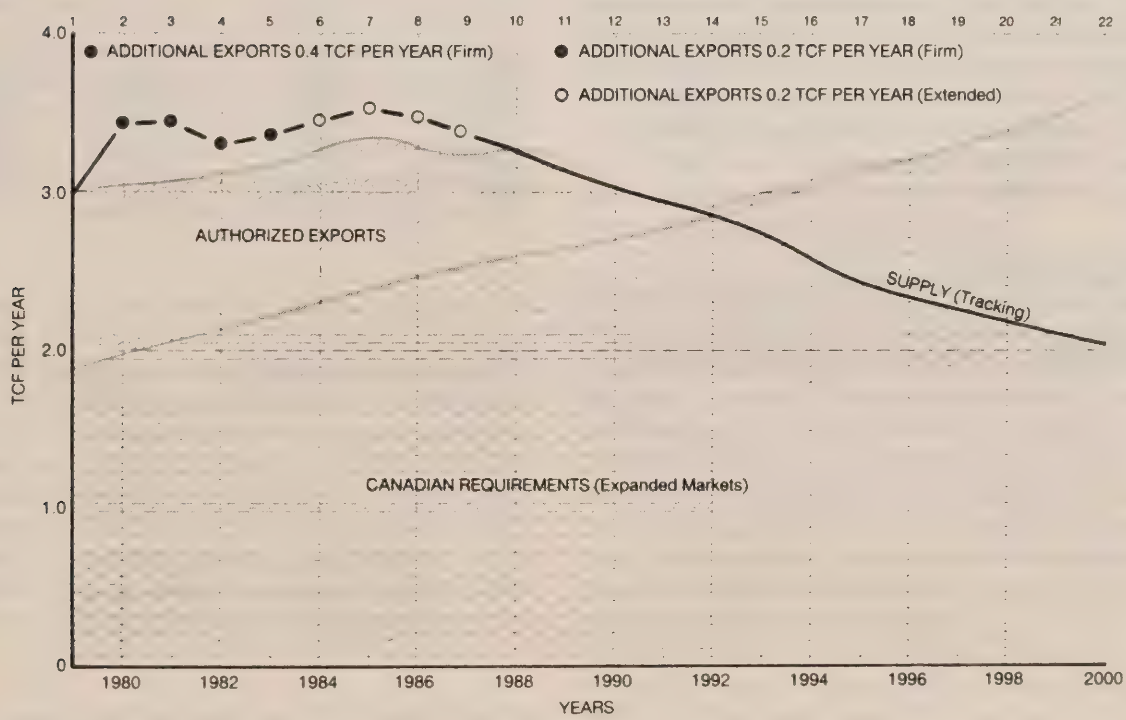


Figure 5-8 **FUTURE DELIVERABILITY TEST**
EXAMPLE CASE 3: 0.4 AND 0.2 TCF PER YEAR ADDITIONAL EXPORTS

Table 5–3

FUTURE DELIVERABILITY TEST

(Bcf/yr @ 1000 Btu/cf)

	DEMAND				SUPPLY[1]			
						Tracking[2]		
Year	Domestic	Export	Total	Capability	No New Export	Case 1[3]	Case 2[4]	Case
1979	1870	1132	3002	3533	3003	3003	3003	3003
1980	1960	1087	3047	3695	3047	3247	3547	3447
1981	2033	1023	3056	3769	3056	3256	3556	3456
1982	2114	1008	3122	3711	3123	3324	3624	3323
1983	2205	962	3166	3560	3166	3367	3646	3366
1984	2300	948	3248	3461	3248	3448	3248	3448
1985	2405	926	3330	3455	3331	3532	3332	3528
1986	2650	815	3285	3378	3285	3485	3285	3457
1987	2525	693	3218	3303	3219	3419	3219	3397
1988	2592	679	3271	3208	3272	3272	3272	3272
1989	2643	547	3190	3105	3190	3179	3150	3159
1990	2697	340	3037	2981	3038	3038	3038	3038
1991	2753	196	2949	2835	2949	2950	2923	2931
1992	2835	54	2889	2742	2889	2877	2854	2861
1993	2931	46	2976	2640	2859	2769	2738	2750
1994	3015	8	3023	2437	2718	2623	2568	2578
1995	3110	6	3116	2341	2554	2453	2432	2438
1996	3196	—	3196	2239	2424	2352	2329	2336
1997	3289	—	3289	2179	2352	2259	2259	2265
1998	3388	—	3388	2109	2263	2201	2184	2190
1999	3490	—	3490	2017	2157	2107	2089	2096
2000	3597	—	3597	1937	2064	2022	2006	2012

(1)Supply is from established reserves only.
(2)Totals may not compare due to rounding.
(3)Assumes export of 200 Bcf/year for four years commencing in 1980.
(4)Assumes export of 500 Bcf/year for three years commencing in 1980.
(5)Assumes export of 400 Bcf/year for two years commencing in 1980, followed by six years of 200 Bcf per year.

Chapter 6
Other Issues

AUTHORIZED EXPORTS

Views of Submittors

British Columbia submitted that the absence of an annual load factor or any minimum take or pay obligation in Westcoast's Licence No. GL-41 created a major uncertainty with respect to future export sales. The Province noted that Northwest Pipeline Corporation, Westcoast's United States customer, had been purchasing considerably less gas on an annual basis than its maximum entitlement. It noted also the resultant reduction in sales and load factor had had the effect of increasing Westcoast's average cost of service to its Canadian customers and placing the BCPC close to a take or pay position with its producers. British Columbia proposed that no additional exports of Canadian natural gas should be approved until existing gas exports made under Licence No. GL-41 were made subject to the take or pay requirements which originally applied to this export contract.

Views of the Board

The Board recognizes that export price increases resulting from reviews undertaken by the Board pursuant to section 11A of the Board's Part VI Regulations rendered ineffective the minimum annual bill pricing provision contained in the contract between Westcoast and Northwest Pipeline Corporation for gas sold under Licence No. GL-41.

Furthermore, the Board notes a decline in demand as United States consumers react to these higher prices and a concern for long–term supply continuity as a result of the Beaver River and Pointed Mountain production problems, despite Westcoast's initiative in securing additional supply from the Province of Alberta. The Board has noticed a further softening of demand in the United States for Canadian gas due to imports into the United States of lower–priced oil products and also because of excess refinery capacity being used to process Alaskan North Slope crude oil with its characteristically higher heavy fuel oil yield.

The Board notes that Westcoast and Northwest Pipeline Corporation are most anxious to increase deliveries and maintain load factor. Westcoast, for its part, has been attaching new supply areas and Northwest Pipeline Corporation has increased its underground storage capacity and has negotiated contracts for off-line sales. These actions will enable a higher load factor to be achieved.

TREATMENT OF ETHANE

Introduction

In Appendix "B" of the Board's Hearing Order GHR-1-78, it was requested that submittors comment on the methodology for determining surplus of ethane. Of the limited number of submittors who did comment on the handling of ethane under the surplus procedure, the majority were in favour of considering the matter of ethane surplus separately from that of natural gas.

Views of Submittors

AGEC

AGEC recommended that ethane be regarded as being independent of, and excluded from, the Board's determination of marketable gas. AGEC submitted that the ethane that could be technically and economically extracted from the gas stream, whether or not it actually was or would be extracted, should be excluded from the calculation of the supply of marketable gas. AGEC testified that this would be equal to 70 to 80 percent of the ethane content of the total gas stream in Canada.

Canadian Superior

Canadian Superior argued that ethane requirements were a part of marketable gas demand, and submitted that only volumes of ethane for which there was an actual demand or a reasonably foreseeable demand should be allocated out of the gas supply as a demand for natural gas. Canadian Superior submitted that allocating out of gas supply extraction capacity volumes or potentially extractable ethane volumes rather than actual ethane demand would have the effect of locking into producers' reservoirs an equivalent volume of natural gas.

Canadian Superior argued that the Board should not treat ethane in the same manner as propane and butanes. Canadian Superior pointed out that the majority of propane and butanes were stripped off at field level to make

gas marketable, and added that volumes of condensates that were not required would still be removed and stored until they could be marketed. Canadian Superior argued that this would not occur in the case of ethane because if there were no demand, ethane would not be extracted, but would remain in the gas stream and be burned as fuel.

Dome

Dome suggested that a methodology similar to its suggestion with regard to the calculation of a natural gas surplus (see section 5.1.2 of Chapter 5) be applied for determining the existence of an exportable surplus of ethane.

Dome submitted that ethane should be treated in the same manner as LPG's in the calculation of the natural gas supply–demand balance. Dome held that allowance for field plant and reprocessing plant shrinkage should be considered as a Canadian demand for natural gas for upgrading purposes regardless of the ultimate destination and use of the ethane and LPG's.

Dome disagreed with Canadian Superior's position that the ethane shrinkage considered by the Board should be limited to that required to supply the reasonably foreseeable Canadian demand for ethane and authorized ethane exports. Dome argued that the future demand for ethane would not be constrained by domestic demand plus presently authorized export volumes because the facilities in place could be reasonably foreseen to expand. Dome stated that whatever volumes of ethane these facilities produced should move to market because the production of ethane, as with LPG's, was an upgrading of a resource for the benefit of Canada.

Dow

Dow recommended that applicants for the export of ethane or synthetic natural gas be required to show only that the volume applied for was surplus to Canadian requirements for ethane or SNG, and that applicants should not be required to show that the proposed export was surplus to domestic requirements for natural gas. Dow suggested that upgraded energy forms, such as ethylene, ethane and SNG be subject to less restrictive export regulations.

Views of the Board

The Board has concluded that, given the existence of ethane extraction facilities in Alberta, it would be more appropriate to treat ethane in a manner similar to other natural gas liquids being extracted than as natural gas for the purpose of surplus determination. Consistent with this finding, the Board has made provision for the shrinkage associated with ethane extraction in its calculation available established reserves in the Current Reserv Test described in Chapter 5.

The following procedure will be employed by the Board future determination of ethane surplus.

Procedure

An estimate of ethane supply from natural gas will be pr pared based on the forecast of natural gas producti from established reserves plus forecast reserves additio available for processing at gas processing plants pre ently recovering ethane and any new plants which are e pected to be available within the forecast period. The es mate of ethane availability will be based on current a forecast rates of ethane recovery from the natural g stream being processed.

The Board, in calculating ethane surplus will compare t expected ethane supply from extraction plants for ea year with the expected domestic requirements plus a thorized ethane exports. An annual ethane surplus will considered to exist to the extent that expected etha availability exceeds expected Canadian demand plus a thorized exports.

DEPARTMENTAL PARTICIPATION IN INQUIRY

The Minister of Energy for Ontario commented in the su mission made on his behalf that the Federal Governme and specifically Energy, Mines and Resources, Canad should participate like other submittors in the examinati of energy matters undertaken from time to time by the N tional Energy Board. The Minister's submission noted th because of the importance of inquiries such as the nat ral gas inquiry, Energy, Mines and Resources, Canad should be requested specifically to present its views energy policy and be subject to the same examination any other intervenor before the Board.

While this view is being brought to the attention of the D partment, the Board recognizes that such action is with the discretion of the Department.

NATIONAL ENERGY CORPORATION

CIC advocated the creation of a National Energy Corp ration, a federal body which would carry out energy su ply planning activities on a national basis. Its princip function would be to ensure in a positive manner that e ergy supply projects based on known Canadian r sources are undertaken and developed on a time sche ule which would meet the essential needs of Canadians.

The Board's only comment on the proposal of CIC is to note that not all energy supply planning activities are within the federal jurisdiction. Planning, research and development are required at many levels to achieve Canadian energy goals.

FREQUENCY OF SUPPLY–DEMAND HEARINGS

There were several suggestions by submittors concerning the frequency of future inquiries of the nature of the two held by the Board in 1978, the oil supply and requirements inquiry and the natural gas supply and requirements inquiry. The question of the desirability of an overall energy supply/demand inquiry in lieu of separate hearings was also raised.

The Board recognizes that the need for considering applications for the export of natural gas may require examination of Canadian natural gas supply, demand and surplus at irregular intervals in the future. Similarly, special circumstances, such as those leading to the recent oil supply/demand inquiry, may require the holding of a special hearing on oil supply/demand matters. Absent such special considerations, the Board sees merit in holding an overall energy supply/demand hearing on a regular basis – say every two or three years – to keep abreast of the changes evolving in oil and gas supply and requirements.

J. S. Stabback
Chairman

J. Farmer
Member

Member

ORDER NO GHR-1-78

IN THE MATTER OF the National Energy Board Act and Section 14(2) and 20(3) thereof; and

IN THE MATTER OF an inquiry, hearing and determination of the supply of Canadian gas, the domestic demand for gas, the method of determining the volume of gas which may be surplus to the reasonably foreseeable requirements in Canada and related matters; under File No. 1122-2-2.

B E F O R E the Board on Wednesday, the 26th day of April, 1978.

WHEREAS the Board deems it advisable in the light of changing circumstances to make an appraisal of the supply of gas in relation to reasonably foreseeable requirements for use in Canada and for authorized exports,

AND WHEREAS the Board stated the general principles respecting surplus calculation procedures in its April 1975 Report on Canadian Natural Gas Supply and Requirements,

AND WHEREAS the Board deferred the development of a structured gas surplus calculation procedure until such time as its application could reasonably be expected to be needed,

AND WHEREAS the Board wishes to receive submissions on the method of determining the volume of gas which may be surplus to the reasonably foreseeable requirements for use in Canada,

AND WHEREAS under Sub-section 14(2) of the National Energy Board Act "The Board may of its own motion inquire into, hear and determine any matter or thing that under this Act it may inquire into, hear and determine",

AND WHEREAS the Board finds it advisable to hold a public inquiry to afford an opportunity for those in the energy sector, the provinces and the general public who have an interest in such subjects to be heard.

IT IS ORDERED THAT:

1. A public inquiry shall be held in the Ballroom of the Holiday Inn, Downtown, 708-8th Avenue S.W., in the City of Calgary in the Province of Alberta commencing on the 11th day of October, 1978 at 9:30 a.m. local time and at such other times and places in such of the Cities of Vancouver, British Columbia; Ottawa, Ontario; Quebec, Quebec and Halifax, Nova Scotia as the Board shall determine having regard to the number of persons who have filed written submissions pursuant to the Board's Notice of Public Inquiry attached hereto and which forms part of this Order to be heard in such cities.

2. The inquiry will be conducted in either of the official languages and simultaneous interpretation facilities will be provided in both Ottawa and Quebec. These facilities will also be provided in other locations if it appears from the written submissions filed with the Board that both official languages will be used in those locations.

3. The purpose of the inquiry referred to in paragraph 1 is to obtain facts and information by means of *viva voce* and written evidence, statements of position, and where necessary, opinions from those persons who have filed written submissions with the Board in response to the Board's Notice of Public Inquiry subject to those facts and information being relevant to the matters set out in paragraph 4 of this Order, provided that such persons in adducing, making or placing before the Board evidence, statements of position, or opinions, or in electing not to do so, in whole or in part, shall be free to present their case in their own manner.

4. The subject matter of the inquiry to which all facts and information shall be relevant is, and the same is declared to be:

(1) Within the context of a review of supply and demand for all forms of energy, consideration of gas, including ethane, during the period ending in the year 2000, in respect to:
   (a) reserves and producibility of Canadian gas including frontier gas,
   (b) domestic demand for gas,
   (c) authorized exports of gas, and
   (d) surplus of gas in Canada.

(2) Consideration of estimates of the extent to which gas can replace other energy forms in the market place and the conditions required for such replacements.

(3) Consideration of methods of determining the volume of gas which may be surplus to the reasonably foreseeable requirements in Canada and authorized exports, taking into account the criteria for determining surplus set forth on page 77 of the 1975 Board Report on Canadian Natural Gas Supply and Requirements reproduced as Appendix "A" attached to and forming part of this Order.

Further particulars in relation to the above matters are set out in Appendix "B" forming part of this Order, entitled "Outline for Submission".

5. Persons who wish to make a submission to the Board on those matters set out in paragraph 4 herein, or to adduce, make or place before the Board facts and information by means of evidence, statements of position or opinions, shall, unless the Board otherwise orders:

(a) state in their submission in which of the official languages and in which of the cities enumerated in paragraph 1 hereof, they wish to be heard;

(b) file and serve, on or before the 1st day of September, 1978, upon the Secretary of the Board thirty-five (35) copies of their written submission in either of the official languages;

(c) serve, on or before the 1st day of September, 1978, upon each other person who has filed a written submission with the Board in response to the Board's Notice of Inquiry, as determined according to a list to be provided from time to time to all submittors by the Secretary of the Board, a copy of their written submission, and shall file proof of service thereof with the Board;

(d) not be entitled to introduce into evidence by *viva voce* or written evidence, or otherwise any subject matter beyond the scope of the subject matter of this hearing;

(e) present witnesses who can answer to the matters contained in the relevant written submission filed with the Board in cross-examination by Board Counsel and by other such persons in accordance with subparagraph (f); and

(f) be entitled to cross-examine witnesses of other such persons on the matters contained in their written submissions, provided such cross-examination and such matters are relevant to the matters set out in paragraph 4 herein;

(g) be entitled to incorporate by reference any submissions or portions of submissions made to the Board a[t] its inquiry on oil supply and demand commencing 2[4] May 1978 set down by Board Order OHR-1-78 date[d] 26th day of January, 1978.

6. Submittors who wish to make a supplemental writte[n] submission at the close of the inquiry are hereby directe[d] to submit, within one week of the close of the hearing such written supplemental submission, as shall be relevant to the matters set out in paragraph 4 herein.

DATED at the City of Ottawa, in the Province of Ontario this 26th day of April, 1978.

NATIONAL ENERGY BOARD

Brian H. Whittle

Secretary

NATIONAL ENERGY BOARD
NOTICE OF PUBLIC INQUIRY

TAKE NOTICE THAT the National Energy Board's Public Inquiry into the supply of and the domestic demand for gas, authorized exports of gas, and the method of determining the volumes of gas which may be surplus to the reasonably foreseeable requirements in Canada, and related matters, convened by Order No. GHR-1-78 shall be held in the Ballroom of the Holiday Inn Downtown, 708-8th Avenue S.W., in the City of Calgary in the Province of Alberta commencing at 9:30 a.m. local time on the 11th day of October 1978, and at such other times and places in such of the cities of Vancouver, British Columbia; Ottawa, Ontario; Quebec, Quebec and Halifax, Nova Scotia as the Board may determine having regard to the number of persons who have filed written submissions.

The inquiry will be conducted in either of the official languages and simultaneous interpretation facilities will be provided in both Ottawa and Quebec. These facilities will also be provided in other locations if it appears from the written submissions filed with the Board that both official languages will be used in those locations.

Interested parties may obtain a copy of the Order including the Outline for Submissions by writing to the Secretary of the Board, Trebla Building, 473 Albert Street, Ottawa, Ontario, K1A OE5 or by telephoning 613-992-5506.

Dated at the City of Ottawa, in the Province of Ontario, this 26th day of April, 1978.

NATIONAL ENERGY BOARD

Brian H. Whittle,

Secretary.

PROTECTION OF CANADIAN REQUIREMENTS PAGE 77
CANADIAN NATURAL GAS SUPPLY AND REQUIREMENTS, APRIL, 1975

(ii) VIEWS OF THE BOARD

The Board is required to determine the reasonably foreseeable requirements of natural gas for use in Canada and to consider for export only the surplus, if any, above this amount. Clearly a procedure for calculating or determining surplus is necessary.

The Board considers that any procedure envisaged should have as many of the following characteristics as possible.

1. It should be easily understood and applied.
2. It should incorporate gas deliverability rather than reserves in the supply considerations.
3. It should be flexible to respond to changing circumstances.
4. It should provide continuing protection for Canadian demand throughout any period of export.
5. It should provide incentive and encouragement to the gas industry.
6. Licensed export commitments should be satisfied to the extent possible.
7. It should reserve for Canadians any benefits from conservation restraints undertaken by Canadians.

However, attainment of the primary objective of an immediately usable and effective procedure, with the capacity for incorporation of all of these characteristics at this time, is not considered practical under prevailing circumstances. The Board recognizes the probability of insufficient near term supplies of gas to cover fully both the quantities of gas licensed for export and the quantities required to meet increasing Canadian demand and sees little possibility of this problem being resolved within the next few years. Since the Board intends to carry out its responsibilities under the Act to ensure that supplies of gas are available to meet Canadian demand before allowing gas exports, the real problem lies in the treatment of existing licences for the export of gas, rather than in theoretical schemes to determine conditions and circumstances under which additional exports of gas might be authorized.

Nevertheless, the Board recognizes that, for the guidanc of both industry and the public, it is desirable to establis general principles which could form the basis of surplu calculation procedure in the future.

The surplus calculation procedure would be based on ga deliverability and gas demand schedules developed for a far into the future as reasonable forecasting accuracy an data dependability will permit. The comparison of thes two schedules will indicate the feasible volumes, rate an timing of exports. Unsatisfied volumes under existing ex port licences would normally have prior call upon an amounts of gas that may become surplus and availabl for export in the future by this procedure. All future expo licences will be for short periods and will be conditione in order that Canadian requirements for gas will be me on a day to day basis, before any gas is exported.

Therefore, beyond stating these general principles, th Board intends to defer the development of a structure gas surplus calculation procedure until such time as i application can reasonably be expected to be needed.

It will, however, conduct and publish an annual revie and reevaluation of the supply, demand and deliverabili of natural gas.

OUTLINE FOR SUBMISSIONS

Submittors are encouraged to use, where applicable, the following outline in the preparation of material. Submittors may incorporate by reference any submissions or portions of submissions made to the Board at its inquiry on Oil Supply and Demand commencing 24th day of May, 1978 set down by Board Order OHR-1-78 dated the 26th day of January, 1978.

Submittors should note that marketable gas is the gas available to the transmission line after removal, and to the extent necessary or desirable, of certain hydrocarbon and non-hydrocarbon compounds present in the raw volumes produced from the reservoir, and after allowance has been made for field and plant fuel and losses.

The Board will welcome submissions on any or all of the subject matters set out in the Order and Outline.

Questions on this outline should be directed to the following members of the Board staff for the matters indicated:

gas reserves and potential	—	E. Kutney Tel: (613) 995-6328
gas demand Tel: (613) 996-2224	—	L.B. Harsanyi
authorized export Tel: (613) 996-1906	—	A.L. Browne
gas deliverability and surplus calculation	—	K. Poole Tel: (613)995-6328

SUPPLY OF NATURAL GAS IN CANADA

It is the intent of the Board to inquire into all aspects of gas supply in Canada, including but not necessarily limited to the following:

1. Reserves currently available i.e., established reserves;
2. Expected reserves additions and ultimate potential;
3. Deliverability;
4. Supply-demand balance;
5. The amount by which current supply exceeds annual requirements.

Insofar as possible, the economic assumptions (especially gas prices) underlying estimates of marketable reserves and deliverability should parallel those used for estimating gas demand and should be specified. In particular, economic assumptions justifying inclusion of frontier supply should be provided.

RESERVES AND DELIVERABILITY OF CANADIAN GAS

Submissions with respect to supply should present marketable reserves estimates and deliverability forecasts which would conform with the following outline:

1. *Reserves* – for each producing province and for each of the frontier regions:
   (a) an estimate of the initial and remaining reserves, pool by pool, as at 31 December 1977;
   (b) a schedule of anticipated additions to reserves in each year from 1978 to 2000; and
   (c) an assessment of ultimate potential.

Producing companies are invited to submit reserves volumes for pools which they operate or in which they have a major interest. Reserves summaries by province or region are requested, particularly those that incorporate original assessments by the company. Transmission companies and other gas purchasers with the requisite data base are asked to provide reserves volumes for pools from which they have contracted gas or expect to do so in future, together with reserves summaries for their respective supply areas and by provinces when possible.

The Board requests submittors of data on reserves additions and ultimate potential to support these data with a summary description of the methodology and a statement of the geological, technological and economic assumptions utilized.

2. Deliverability
   (a) An estimate by transmission system of the capability to produce gas year by year to the year 2000 from Canadian reserves to meet demand, including authorized exports, under a "most likely" case of supply, demand and pricing.
   (b) A total Canadian gas supply/demand balance.
   (c) An estimate of the expected capability to produce gas from Canadian reserves assuming an unlimited market on a provincial and total Canada basis, using the pricing assumptions underlying the "most likely" case of supply and demand.

With respect to deliverability the Board would prefer that a pool by pool forecasting technique be used by those submittors who have access to the requisite data base. Submittors should outline the technique used to forecast deliverability and state all major assumptions used in the forecast. Wherever possible the Board would appreciate receiving basic deliverability data used in the forecasts especially for new pools, pools which have had recent development and pools on which the data have not been previously submitted to the Board.

3. Synthetic Natural Gas
   An estimate of the sources, geographical location and supply potential of synthetic natural gas, year by year to the year 2000, together with economic justification.

DOMESTIC DEMAND FOR GAS

Submittors are encouraged to present estimates of gas demand in the context of a total energy forecast. Submittors using such an approach are requested to provide a breakdown of Canadian energy demand by energy type including renewable energy. In order that comparative evaluations of the submitted gas forecasts can be made, all submittors are requested to make explicit their basic forecast assumptions with respect to variables such as economic growth, population growth, relative prices of various energy types, market shares, and expansion of energy types into geographic areas not presently using that energy form. Submittors should if possible indicate the measure of uncertainty they attach to the economic and other assumptions.

All forecasts of gas demand should be expressed in millions of Btu's and should be accompanied by actual historical data for one year or more.

Existing Gas Transmission Systems

Submittors are requested to provide forecasts of the Canadian requirements for marketable gas in market areas presently served by existing transmission facilities for each calendar year for the years 1978 to 2000 inclusive on the basis of each of the following alternatives as to the relationship at Toronto of the city-gate price of gas to the refinery gate price of crude oil:

(a) maintenance of the present relationship of about 85 percent of the crude oil price;
(b) successive increments of 5 percentage points per year to the present relationship, starting 1 January 1979, to a maximum of 100 percent of the price of crude oil; and
(c) a decrease in the price of gas below its presen relationship, starting 1 January 1979, to 75 percent of the price of crude oil.

In case (c) comments would be welcomed on the economic impact of such penetration on competing energ industries.

Extension of Existing Transmission Systems

Submittors are requested to provide estimates of the extent to which gas could penetrate energy markets beyonc existing transmission systems. Such estimates should, i possible, be accompanied by assessments of the exten to which gas would displace in the market place othe energy forms; that is, oil (distillate and heavy fuels), coa and electricity.

It is requested that a clear explanation be provided of th manner and degree in which any assumption was varie in the forecasts and the conditions needed for realizatio of the displacement.

To assist the Board in its assessment of this matter, sub mittors are requested to provide:

(1) estimates of the demand for gas for each yea and the required city-gate selling price relation ship to crude oil required to attain market pene tration,
(2) the likely economic feasibility and timing of pro viding the required transmission and distributio facilities to enable such sales to be made; and
(3) an estimate of the economic impact on compet ing energy industries.

Details of Gas Demand

Submittors are requested to provide forecasts of domesti requirements for marketable gas by province and the ter ritories, and for each of the following classes of end-use for each of the following sectors and purposes.

(a) residential,
(b) commercial,
(c) industrial, in this case broken down by use
   i) as feedstock for the manufacture of ammonia,
   ii) as feedstock for the manufacture of methanol,
   iii) as feedstock for other chemicals c petrochemicals,
   iv) in other industrial uses,
(d) thermal generation of electricity,
(e) gas re-processing (straddle) plants,

(f) transmission and distribution compressor fuel, losses and company use.

Energy Conservation

Submittors who have prepared forecasts will likely include the effects of some conservation measures. "Conservation measures" embrace:

- those programmes designed specifically to reduce energy demand, and
- those policies, whether general or specific, which may have a bearing on the consumption, conservation and price of any or all energy forms, and which may have a direct or indirect impact on energy demand.

Submittors are asked to specify what conservation measures they have assumed and what effects these have on their energy and gas forecasts. In addition, submittors are also encouraged to comment on and quantify if possible any additional reductions in demand, by end-use, resulting from conservation measures which, though feasible, are not anticipated to occur.

NOTE: (1) Ethane from field processing plants is part of field plant shrinkage.
(2) Ethane from straddle plants is part of marketable gas demand and included in item (e) above.

DETERMINATION OF SURPLUS

(a) Submittors are requested to outline their proposed methodology for determining surplus of gas in Canada having regard to the trends in the discovery of gas in Canada. The methodology should take into account such factors considered relevant and give due consideration to Appendix "B" which provides the Board's views on the matter as published on page 77 of its April 1975 Report on "Canadian Natural Gas Supply and Requirements". Submittors should give reasons for their particular choice of methodology for surplus determination.
(b) Submittors are requested to comment on the methodology for determining surplus of ethane.
(c) Using their supply and demand estimates submittors are invited to illustrate their suggested methodology for determining surplus.

INITIAL ESTABLISHED RESERVES OF MARKETABLE NATURAL GAS

NEB Estimates Significantly Different From Estimates of Provincial Agencies
31–12–77

BRITISH COLUMBIA

Field & Pool or Pool Group	Bcf @ 14.73 psia and 60°F	
	NEB	Provincial Agency[1)]
BEG		
Baldonnel A,B & C	94	129
CABIN		
Slave Point A,B & C	46	110
CLARKE LAKE		
Slave Point A	1100	1244
KOTCHO LAKE		
Slave Point A, B & C	52	150
KOTCHO LAKE EAST		
Slave Point A, B & C	53	164
LAPRISE CREEK		
Baldonnel	573	769
NIG CREEK		
Baldonnel A	378	474
PETITOT RIVER		
Slave Point	30	67
SIERRA		
Pine Point A & B	837	574
VELMA		
Gething	46	96
YOYO		
Slave Point/Pine Point	862	1311

ALBERTA

Field & Pool or Pool Group	Bcf @ 14.73 psia and 60°	
BENJAMIN		
Rundle A & B	151	174
BRAZEAU RIVER		
Elkton–Shunda A & B	1547	1492
CRAIGEND		
Viking C	86	149
CROSSFIELD		
Wabamun A	575	497
CROSSFIELD EAST		
Wabamun A	570	497
DUNVEGAN		
Debolt A,B,C & D	857	895
EDSON		
Eklton A & Shunda A & B	1607	1701
FERRYBANK		
Belly River C	32	65
GHOST PINE		
Upper Mannville C associated, G,H, P & U	130	159
Upper Mannville Q Associated	75	104
HARMATTAN EAST		
Rundle associated	750	875
HOMEGLEN–RIMBEY		
D–3 associated & solution	880	818
HOTCHKISS		
Bluesky A,E & other	52	25
Debolt A & B, Shunda A	136	101
IRRICANA		
Wabamun A	57	14
JUMPING POUND WEST		
Rundle C	199	378
LEISMER		
Clearwater A	254	199
LONE PINE CREEK		
Wabamun A	277	368
MARLBORO		
Leduc A	65	99
MARTEN HILLS		
Wabiskaw A & Wabamun A,C & other	967	900
MORLEY		
Rundle	42	12
NEVIS		
Blairmore A & Mannville other	16	57
PADDLE RIVER		
Jurassic–Detrital–Rundle	300	348
RICINUS WEST		
D–3A	796	845
SWAN HILLS		
Beaverhill Lake A & B solution	279	308
SWAN HILLS SOUTH		
Beaverhill Lake A & B solution	182	229
TWINING		
Lower Mannville A & Rundle A associated & solution	245	288
WESTEROSE SOUTH		
D–3A	1426	1373
MILK RIVER		
Pool No. 1	4644	4970
MEDICINE HAT		
Pools No. 1, 3 & 4	3598	3539

Field & Pool or Pool Group	Bcf @ 14.73 psia and 60°F	
2ND WHITE SPECKS		
Pool No. 1	1244	1193

[1]data for British Columbia from British Columbia Ministry of Mines and Petroleum Resources Report, Hydrocarbon and By–Product Reserves in British Columbia 31 December 1977.

Data for Alberta from AERCB Report 78–18.

PROJECTIONS OF DEMOGRAPHIC AND ECONOMIC GROWTH

In addition to the base case economic forecast discussed in Chapter 3 of the main body of this report, the Board has prepared a more optimistic forecast of the Canadian economy. There is a basic difference in the philosophies behind the base case and the high case forecasts. The base case projects the Canadian economy by assuming "best guess" parameters for exogenous variables in line with historical economic patterns but in the light of current economic conditions. The high forecast, on the other hand, is optimistic because it assumes that all important exogenous events in the future will turn out to be conducive to real economic growth.

The high case forecast is characterized by stronger growth in real GNP, lower unemployment rates and moderately higher inflation relative to the base case projection. A more detailed examination of the two forecasts is presented in the following table.

The general assumptions used in the base case are discussed in Chapter 3. Below, they are contrasted with those used in the high case.

Since the rate of growth in real GNP is approximately equal to the sum of the rates of growth of employment and of productivity, different assumptions regarding both these variables were made to produce the high demand case. In particular it was assumed that both the average labour force participation rates and the average productivity of the Canadian worker would be higher for the high case projection. Furthermore, immigration is assumed to increase by 10,000 a year over the base case level of 100,000 starting in 1983. It peaks at 140,000 in 1986 and remains constant thereafter throughout the forecast period.

To increase the demand for Canadian goods relative to the base case, savings rates were assumed to be lower in the high case than in the base case. In addition it was assumed that the Canadian dollar would be lower in terms of the United States dollar, providing a boost to exports and reducing imports. In the high case the Canadian dollar was assumed to average 87 cents U.S. in 1978 and to appreciate 1 cent per year beginning in 1981 and stabilize at 92 cents in 1985 versus a constant 92 cents in the base case.

PROJECTIONS OF THE CANADIAN ECONOMY

Range of Forecasts
NEB Forecast

	1977 (Level)	Actual 1960-76	Forecast	1978-80 (Percent Per Annum)	1981-85	1986-2000	2000 (Level)
GNP			Base	4.6	4.5	3.4	201.6
($1961 billions)	85.6	5.1	High	5.1	5.0	4.0	228.4
Population			Base	1.2	1.1	1.0	29.8
(millions)	23.4	1.6	High	1.2	1.3	1.2	31.0
Employment			Base	2.0	2.3	1.5	14.5
(millions)	9.8	3.0	High	2.2	2.7	1.8	15.5
Households			Base	2.7	2.4	1.3	10.9
(millions)	7.3	2.9	High	2.7	2.4	1.5	11.2
Unemployment			Base	8.1	6.8	5.2	4.1
Rate (%) *	8.1	5.5	High	7.6	5.7	4.1	4.0
CPI (1961 = 1)**	2.157	1.988	Base	2.703	3.524	6.762	6.762
			High	2.747	3.584	7.827	7.827
Personal disposable							
income			Base	3.2	4.7	3.0	145.9
($1961 billions)	67.7	5.2	High	3.3	5.4	4.0	174.8
RDP commercial							
sector			Base	4.0	4.5	3.1	80.7
($1961 billions)	36.5	5.4	High	4.2	5.0	3.9	94.0
RDP industrial							
sector			Base	6.1	4.4	3.3	68.5
($1961 billions)	28.3	4.8	High	6.8	4.8	3.7	75.3

* Period average shown, rather than growth rate.
** Annual level at period end shown rather than growth rate.

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	1576	1703	2025	2278	2875
A & S	1499	1619	1850	2113	2759
Consolidated	1511	1636	–	–	–
Dome	1491	1599	1856	2095	2626
Gulf	1495	1646	2016	2413	3113
Home Oil	1790	1957	2260	2489	2942
Imperial	1498	1602	2029	2370	2934
IPAC	1523	1673	1973	2218	2734
Norcen	1552	1673	1883	2058	2422
PanCanadian	1680	1861	2129	2371	2921
Polar Gas	1494	1621	1920	2268	2972
ProGas	1515	1633	1841	2076	2482
Shell	1493	1590	1869	2099	2558
TransCanada	1514	1605	1802	2030	2563
NEB	1506	1620	1912	2134	2893

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
ONTARIO
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	736	787	932	1070	[illegible]
A & S	688	711	794	911	[illegible]
Consolidated	671	688	–	–	–
Dome	660	676	783	881	[illegible]
Gulf	688	721	857	1004	[illegible]
Imperial	702	768	974	1116	[illegible]
IPAC	666	701	829	941	[illegible]
Norcen	679	686	769	837	[illegible]
NCGas	679	686	769	836	[illegible]
PanCanadian	676	683	803	952	[illegible]
Polar Gas	–	720	850	976	[illegible]
ProGas	670	700	775	870	[illegible]
Shell	681	714	835	945	[illegible]
Sun	691	742	875	1031	–
TransCanada	671	661	728	845	[illegible]
Union Gas	–	721	858	993	[illegible]
NEB	683	712	821	925	[illegible]

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
QUEBEC
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	81	84	98	108	129
A & S	88	99	124	150	226
Consolidated	86	95	–	–	–
Dome	85	110	140	173	236
Gaz Métropolitain	91	94	117	139	189
Quebec	–	–	–	91	–
Gulf	85	91	117	148	211
Imperial	85	90	117	145	185
IPAC	99	109	141	179	248
Norcen	91	93	112	118	163
PanCanadian	95	117	153	193	285
Polar Gas	–	117	152	192	286
ProGas	83	90	108	128	169
Shell	85	89	105	122	156
Sun	85	92	127	155	–
TransCanada	87	93	117	138	195
NEB	85	96	112	134	202

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
MANITOBA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	68	73	86	100	[illegible]
A & S	69	71	78	89	[illegible]
Consolidated	62	65	–	–	–
Dome	64	68	77	89	[illegible]
Manitoba	65	71	86	98	[illegible]
Gulf	65	70	84	96	[illegible]
Imperial	–	–	–	–	–
IPAC	71	77	88	103	[illegible]
Norcen	70	74	79	89	[illegible]
PanCanadian	64	70	81	96	[illegible]
Polar Gas	–	70	80	95	[illegible]
ProGas	64	70	80	90	[illegible]
Shell	64	67	74	79	[illegible]
TransCanada	65	65	72	78	[illegible]
NEB	65	70	80	90	[illegible]

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
SASKATCHEWAN
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	104	110	132	156	210
A & S	100	102	113	131	182
Consolidated	99	103	–	–	–
Dome	105	109	120	130	149
Gulf	95	100	115	132	166
Imperial	–	–	–	–	–
IPAC	95	100	117	140	193
Norcen	105	111	118	127	146
PanCanadian	105	105	122	143	195
Polar Gas	–	117	145	176	250
ProGas	95	98	108	115	130
SPC	97	95	102	109	121
Shell	107	111	119	124	145
TransCanada	98	95	107	120	155
NEB	97	103	113	128	202

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
BRITISH COLUMBIA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	150	161	208	244	325
A & S	150	165	192	224	306
B.C. Hydro	143	179	221	256	330
Consolidated	144	155	–	–	–
Dome	145	155	197	232	309
Gulf	144	182	222	283	354
Imperial	147	163	240	287	359
IPAC	147	159	191	229	313
Norcen	153	166	219	256	342
PanCanadian	170	186	220	247	347
Polar Gas	–	167	213	249	318
ProGas	145	155	190	225	295
British Columbia	150	159	–	214*	–
Shell	146	156	192	220	284
TransCanada	143	153	197	225	291
Westcoast	154	175	218	267	343
NEB	143	158	213	239	360

* Year 1992

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
ALBERTA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AERCB	496	603	648	686	691
AGTL	438	487	568	601	697
A & S	404	471	549	608	748
Consolidated	450	530	–	–	–
Dome	432	481	539	591	710
Gulf	418	482	622	749	991
Home*	580	690	760	740	750
Imperial	–	–	–	–	–
IPAC	445	527	607	627	674
Norcen	454	543	586	631	665
PanCanadian**	570	700	750	740	690
Polar Gas	–	430	480	580	750
ProGas	458	520	580	648	745
Shell	411	454	545	611	683
TransCanada	450	538	581	624	659
NEB	434	483	574	619	726

* Includes pipeline fuel and losses, shrinkage and ethane feedstock.
** Includes pipeline fuel and losses.

NET SALES OF NATURAL GAS – (EXISTING MARKETS) RESIDENTIAL
CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	325	350	421	488	617
Consolidated	328	341*	–	–	–
Dome	336	355	405	459	566
Gulf	333	355	415	466	524
Imperial	414	480	588	675	793
IPAC	361	382	436	500	609
Polar Gas	–	343	393	452	570
ProGas	342	365	415	461	549
Shell	407	426	481	500	554
TransCanada	345	354	381	396	434
NEB	338	350	395	440	545

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) COMMERCIAL CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	313	343	426	505	643
Consolidated	305	324*	–	–	–
Dome	318	338	395	467	613
Gulf	335	371	463	550	696
Imperial	281	295	369	426	526
IPAC	315	345	415	490	628
Polar Gas	–	367	450	547	728
ProGas	329	353	425	492	592
Shell	248	263	301	330	373
TransCanada	330	352	397	420	514
NEB	336	366	442	499	632

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) PETROCHEMICALS CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	200
AGTL	165	182	211	212	20
Consolidated	–	–	–	–	–
Dome	177	193	221	239	28
Gulf	123	157	231	276	41
Imperial	80	75	94	110	15
IPAC	–	–	–	–	–
Polar Gas	–	157	184	203	20
ProGas	150	170	200	225	25
Shell	85	88	110	122	12
TransCanada	204	270	273	277	27
NEB	165	176	217	237	25

NET SALES OF NATURAL GAS – (EXISTING MARKETS) RESIDENTIAL/COMMERCIAL CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	638	693	847	993	1260
Consolidated	632	665*	–	–	–
Dome	654	693	799	926	1179
Gulf	668	726	877	1015	1220
Imperial	695	775	957	1101	1319
IPAC	675	727	852	990	1237
Polar Gas	–	710	843	999	1298
ProGas	671	718	840	953	1141
Shell	655	689	783	830	927
TransCanada	675	706	778	816	948
NEB	674	716	837	939	1177

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) INDUSTRIAL CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	200
AGTL	611	651	779	897	12
Consolidated	879	971*	–	–	–
Dome	551	589	700	789	10
Gulf	572	615	778	971	13
Imperial	617	651	873	1053	14
IPAC	777	887	1068	1173	14
Polar Gas	–	679	820	991	13
ProGas	613	654	738	848	10
Shell	630	702	863	1038	14
TransCanada	557	578	691	884	12
NEB	548	602	717	815	13

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) THERMAL GENERATION CANADA
Comparison of Forecasts
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	163	178	189	177	183
Consolidated	–	–	–	–	–
Dome	110	123	136	142	155
Gulf	131	147	130	150	135
Imperial	106	101	105	106	25
IPAC	71	60	53	55	57
Polar Gas	–	75	73	75	81
ProGas	81	91	63	50	35
Shell	124	111	113	110	107
TransCanada	78	51	60	53	53
NEB	120	126	141	143	153

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Canada
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	337.5	350.1	394.9	439.6	544.7
Commercial	336.3	365.9	441.7	499.4	632.0
Petrochemical	164.6	176.3	217.2	237.2	255.5
Other Industrial	548.1	601.5	716.8	815.4	1307.7
Thermal Electric Generation[1]	119.9	126.2	141.1	142.6	152.9
Total Net Sales	1506.4	1620.0	1911.7	2134.2	2892.8

[1] Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Manitoba
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	23.5	24.3	26.0	28.3	32.[illegible]
Commercial	20.5	22.7	26.4	29.3	36.[illegible]
Petrochemical	3.5	3.5	3.5	3.5	3.[illegible]
Other Industrial	16.8	19.0	23.2	27.8	46.[illegible]
Thermal Electric Generation[1]	0.2	0.2	0.4	0.6	1.[illegible]
Total Net Sales	64.5	69.7	79.5	89.5	119.[illegible]

[1] Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Quebec
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	18.2	19.4	21.5	25.5	34.5
Commercial	15.5	17.9	22.1	26.9	37.3
Petrochemical	–	–	–	–	–
Other Industrial	51.5	58.3	68.1	81.5	130.2
Thermal Electric Generation[1]	–	–	–	–	–
Total Net Sales	85.2	95.6	111.7	133.9	202.0

[1] Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Saskatchewan
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	28.5	29.3	31.5	35.0	41.[illegible]
Commercial	9.5	12.2	13.6	14.5	16.[illegible]
Petrochemical	–	–	–	–	–
Other Industrial	51.1	54.7	64.5	74.5	140.[illegible]
Thermal Electric Generation[1]	7.5	6.3	3.5	3.9	3.[illegible]
Total Net Sales	96.6	102.5	113.1	127.9	201.[illegible]

[1] Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Ontario
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	139.0	146.9	169.9	190.6	242.7
Commercial	167.8	181.0	226.9	258.9	330.4
Petrochemical	29.0	32.0	32.0	33.0	33.0
Other Industrial	295.0	311.6	357.2	403.7	628.2
Thermal Electric Generation[1]	51.9	40.0	35.3	39.2	49.8
Total Net Sales	682.7	711.5	821.3	925.4	1284.1

[1] Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Alberta
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	85.3	84.4	91.7	99.5	118.[illegible]
Commercial	87.1	93.5	104.1	111.7	135.[illegible]
Petrochemical	127.6	136.3	177.2	196.2	214.[illegible]
Other Industrial	79.8	96.1	127.7	134.8	198.[illegible]
Thermal Electric Generation[1]	54.6	72.3	73.0	76.3	58.[illegible]
Total Net Sales	434.4	482.6	573.7	618.5	725.[illegible]

[1] Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – British Columbia
(Bcf/Year)

	1978	1980	1985	1990	2000
Residential	43.0	45.6	54.3	60.8	75.0
Commercial	35.9	38.7	48.6	58.2	76.0
Petrochemical	4.5	4.5	4.5	4.5	4.5
Other Industrial	53.8	61.9	76.1	93.1	164.8
Thermal Electric Generation(1)	5.8	7.3	29.0	22.7	39.6
Total Net Sales	143.0	158.0	212.5	239.3	359.9

(1) Includes generation of electricity by industry as well as utilities

EXPANSION VOLUMES OF NATURAL GAS BY SECTOR – QUEBEC

Comparison of Estimates

(Bcf/Year)

	1980	1985	1990	1995	2000
RESIDENTIAL					
Dome	1.0	12.0	14.4	15.5	16.4
Home(1)	4	13	18	22	–
Imperial	0	14	20	27	34
IPAC Res./Com.	1	8	17	33	35
Norcen – Gaz Métro					
moderate penetration	0.2	2.5	9.5	14.9	19.2
ultimate penetration	0.4	17.2	23.0	31.0	36.0
Q&M	2.0	32.9	56.3	81.7	106.7
Shell(2)	4.6	22.5	34.2	57.4	59.0
Sun(3)	3.2	24.0	39.4	53.7	–
TCPL(4)	0	10	38	46	55
NEB(4)	3.6	19.1	30.8	39.5	41.8
COMMERCIAL					
Dome	0	9.7	11.7	12.5	12.8
Home(1)	9	23	33	44	–
Imperial	0	2	3	5	9
IPAC	–	–	–	–	–
Norcen - Gaz Métro					
moderate penetration	0.1	0.7	4.7	7.8	10.6
ultimate penetration	0.3	11.3	14.3	19.0	22.2
Q&M	1.7	25.7	43.8	63.4	82.7
Shell(2)	4.1	17.8	29.9	45.3	46.8
Sun(3)	4.8	23.3	42.5	70.1	–
TCPL(4)	0	12	36	45	50
NEB(4)	3.5	20.5	35.0	46.4	53.7

EXPANSION VOLUMES OF NATURAL GAS BY SECTOR – QUEBEC (Cont'd)

Comparison of Estimates

(Bcf/Year)

	1980	1985	1990	1995	20[illegible]
INDUSTRIAL					
Dome	1.1	50.2	52.4	56.5	59.[illegible]
Home(1)	20	44	60	80	–
Imperial	3	36	41	4	49
IPAC	1	50	52	57	60
Norcen – Gaz Métro					
moderate penetration	7.5	15.3	49.1	51.2	5[illegible]
ultimate penetration	7.5	65.4	117.0	127.5	14[illegible]
Q&M	5.9	67.8	103.2	139.3	16[illegible]
Shell(2)	8.0	26.7	44.7	73.0	9[illegible]
Sun(3)	12.8	72.9	85.9	97.9	–
TCPL(4)	13	75	134	127	13[illegible]
NEB(4)	7.2	38.4	66.0	79.8	9[illegible]
TOTAL NET SALES					
Dome	2.1	71.9	78.3	84.5	8[illegible]
Home(1)	33	80	111	146	–
Imperial	3	52	64	76	9[illegible]
IPAC	1	58	69	90	9[illegible]
Norcen – Gaz Métro					
moderate penetration	7.8	18.5	63.3	73.9	8[illegible]
ultimate penetration	8.2	93.9	154.3	177.5	20[illegible]
ProGas(4)	27	70	95	105	11[illegible]
Q&M	9.6	126.4	203.3	284.4	35[illegible]
Shell(2)	16.7	67.0	108.8	175.7	19[illegible]
Sun(3)	20.8	120.2	167.8	221.7	–
TCPL(4)	13	97	208	218	24[illegible]
NEB(4)	14.3	78.0	131.8	165.7	18[illegible]

Notes: (1) Adopted TransCanada submission to the 1978 Oil Inquiry Exhibit 1722-9-3, Chapter IX, Table P. 10 Case II.
(2) Starting year, 1982.
(3) Re-adopted Hycarb study to 1978 Oil Inquiry, tables 5 to 7.
(4) Starting year, 1981.

EXPANSION VOLUMES OF NATURAL GAS BY SECTOR – ATLANTIC
Comparison of Estimates
(Bcf/Year)

	1981	1985	1990	1995	2000
RESIDENTIAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	0.9	2.9	6.9	10.8	–
Q&M	0.1	4.0	8.6	12.9	17.3
NEB(3)	0.9	3.8	7.3	10.2	11.0
COMMERCIAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	0.7	1.6	6.6	11.9	–
Q&M	0.1	2.8	6.0	9.0	12.2
NEB(3)	0.7	3.0	6.2	8.7	10.3
INDUSTRIAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	16.1	42.9	48.6	52.1	–
Q&M	0.5	9.6	20.3	33.0	38.3
NEB(3)	11.8	21.8	31.6	39.3	43.7
THERMAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	12.3	16.2	5.1	2.3	–
Q&M	3.0	17.5	9.8	13.1	16.4
NEB(3)	2.9	13.5	5.4	0	0
TOTAL NET SALES					
IPAC(1)	1	7	18	32	34
Nova Scotia(2)	28.4	63.8	67.1	77.1	–
Q&M	3.7	34.1	44.8	68.0	84.4
NEB(3)	16.3	42.1	50.5	58.2	65.0

(1) Starting year 1983.
(2) Starting year 1982 for Industrial and Thermal and 1983 for Residential and Commercial
(3) Starting year 1982.

ESTIMATES OF NATURAL GAS NET SALES INCLUDING GAS EXPANSION – QUEBEC
Comparison of Estimates
(Bcf/Year)

	1980	1985	1990	1995	2000
RESIDENTIAL					
AGTL(1)	20.4	56.8	84.6	115.5	145.4
Dome	22.0	38.8	46.4	53.0	59.7
Home(2)	25	35	40	45	–
Imperial	20	43	73	101	111
IPAC Res/Con(5)	41.7	57.9	81.2	111.3	126.8
Norcen – Gaz Métro					
moderate penetration	20.5	23.9	27.1	33.3	37.4
ultimate penetration	20.7	38.6	40.6	49.4	54.2
Q&M	18.9	55.2	83.2	113.3	143.0
Shell(3)	24.4	44.3	57.7	82.5	84.6
Sun(4)	20.6	43.4	59.9	75.0	–
TCPL(5)	20	32	61	70	80
NEB(5)	23.2	40.6	56.3	69.4	76.3
COMMERCIAL					
AGTL(1)	16.9	45.5	67.6	91.4	114.9
Dome	18.0	31.8	38.1	43.5	49.0
Home(2)	26	44	58	73	–
Imperial	23	31	33	36	46
IPAC(5)	–	–	–	–	–
Norcen – Gaz Métro					
moderate penetration	14.7	17.4	19.1	23.2	25.8
ultimate penetration	14.9	28.0	28.7	34.4	37.4
Q&M	15.6	44.0	66.0	89.4	112.5
Shell(3)	20.1	34.7	48.2	64.8	67.3
Sun(4)	19.8	40.8	61.4	90.1	–
TCPL(5)	15	29	54	65	71
NEB(5)	22.0	42.6	61.9	78.1	91.0

ESTIMATES OF NATURAL GAS NET SALES INCLUDING GAS EXPANSION – QUEBEC
(Cont'd)
Comparison of Estimates
(Bcf/Year)

	1980	1985	1990	1995	20
INDUSTRIAL					
AGTL(1)	56.3	122.3	159.0	194.4	21
Dome	71.7	141.5	166.7	193.7	21
Home(2)	88	122	151	184	[illegible]
Imperial	50	95	103	110	12
IPAC(5)	77.5	141.3	166.3	194.2	21
Norcen – Gaz Métro					
moderate penetration	65.5	88.8	135.5	158.3	18
ultimate penetration	65.5	138.9	203.4	234.6	27
Q&M	52.0	117.2	153.2	187.6	21
Shell(3)	66.9	93.2	124.5	166.6	20
Sun(4)	72.8	163.1	201.4	244.6	-
TCPL(5)	80	153	231	247	28
NEB(5)	67.2	106.5	147.5	180.4	22
TOTAL NET SALES					
AGTL(1)	93.6	224.6	311.2	401.3	48
Dome	111.7	212.1	251.2	290.2	32
Home(2)	139	201	249	302	[illegible]
Imperial	93	169	209	247	27
IPAC(5)	119.2	199.2	247.5	305.5	34
Norcen – Gaz Métro					
moderate penetration	100.7	130.1	181.7	214.8	25
ultimate penetration	101.1	205.5	272.7	318.4	36
ProGas(5)	119	178	223	257	28
Q&M	86.5	216.4	302.4	390.3	46
Shell(3)	111.4	172.2	230.4	313.9	35
Sun(4)	113.2	247.3	322.7	409.7	[illegible]
TCPL(5)	115	214	346	382	43
NEB(5)	112.4	189.7	265.7	327.9	39

Notes: (1) Adopted Q&M gas expansion volumes.
(2) Adopted TransCanada submission to the 1978 Oil Inquiry. hibit 1722-9-3, Chapter IX, table P. 10 Case II.
(3) Starting year, 1982.
(4) Re-adopted Hycarb study to 1978 Oil Inquiry, tables 5 to 7
(5) Starting year, 1981.

ESTIMATES OF TOTAL NATURAL GAS NET SALES INCLUDING GAS EXPANSION – CANADA
Comparison of Estimates
(Bcf/Year)

	1978	1980	1985	1990	2000
AGTL	1576	1713	2186	2526	3311
Dome	1491	1601	1928	2173	2714
Home Oil	1790	1990	2340	2600	3100
Imperial	1498	1605	2081	2434	3026
IPAC	1523	1674	2038	2305	2863
Norcen – moderate penetration	1552	1681	1902	2121	2510
Norcen – ultimate penetration	1552	1681	1977	2212	2622
ProGas[1]	1515	1698	1911	2171	2595
Shell[2]	1493	1718	1936	2208	2756
TransCanada[1]	1514	1671	1899	2238	2806
NEB[1]	1506	1687	2032	2316	3147

[1] Starting year of expansion, 1981.
[2] Starting year of expansion, 1982.

NEB ESTIMATES OF OIL DISPLACED AS A RESULT OF GAS PENETRATION
(Base Case)
(Mb/d)

	1985	1990	1995	2000
Quebec				
Light Fuel Oil				
No expansion case	112.3	110.9	109.9	108.0
Expansion case	98.0	88.1	81.2	78.1
Displacement	14.3	22.8	28.7	29.9
Heavy Fuel Oil				
No expansion case	124.5	129.8	140.1	158.7
Expansion case	103.7	94.1	95.9	107.0
Displacement	20.8	35.7	44.2	51.7
Atlantic				
Light Fuel Oil				
No expansion case	50.0	52.3	54.4	55.9
Expansion case	47.3	47.2	47.5	48.5
Displacement	2.7	5.1	6.9	7.4
Heavy Fuel Oil				
No expansion case	99.0	90.8	103.2	121.5
Expansion case	83.1	73.6	84.5	100.5
Displacement	15.9	17.2	18.7	21.0

DEMAND FOR CANADIAN GAS BY AREAS

(Bcf/yr. @ 1000 Btu/cf)

	ALBERTA				BRITISH COLUMBIA		EAST OF ALBERTA			TOTAL CANADA		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Domestic	Export	AGTL Fuel	Reprocessing	Domestic	Export	Domestic Base Case	Domestic Expansion	Export	Domestic (1+3+4+5+7+8)	Export (2+6+9)	Total (10+11)
1979	455	516	23	176	178	303	1038	0	313	1870	1132	3002
1980	488	512	24	196	186	304	1066	0	271	1960	1087	3047
1981	508	487	24	196	196	303	1093	16	233	2033	1023	3056
1982	523	472	23	198	205	303	1115	50	233	2114	1008	3122
1983	547	426	24	199	216	303	1143	76	233	2205	962	3166
1984	560	411	25	199	229	304	1184	103	233	2300	948	3248
1985	580	390	26	201	243	303	1222	133	233	2405	926	3330
1986	573	286	25	227	248	303	1252	145	226	2470	815	3285
1987	583	164	23	224	252	303	1284	159	226	2525	693	3218
1988	606	149	24	220	257	304	1313	172	227	2592	679	3271
1989	615	80	24	208	263	252	1347	186	215	2643	547	3190
1990	625	80	23	207	257	110	1384	201	150	2697	340	3037
1991	635	73	22	207	265	55	1415	209	69	2753	196	2949
1992	646	46	22	215	276	0	1458	218	8	2835	54	2889
1993	672	38	23	216	288	0	1505	227	8	2931	46	2976
1994	683	0	23	216	299	0	1557	237	8	3015	8	3023
1995	696	0	24	217	312	0	1614	247	6	3110	6	3116
1996	703	0	25	219	324	0	1671	254	0	3196	0	3196
1997	711	0	26	219	338	0	1734	261	0	3289	0	3289
1998	719	0	27	219	352	0	1802	269	0	3388	0	3388
1999	727	0	28	219	368	0	1874	274	0	3490	0	3490
2000	734	0	29	220	384	0	1950	280	0	3597	0	3597
TOTAL	13589	4128	535	4618	5936	3450	31021	3717	2890	59416	10468	69884

—Figures may not add due to rounding.

—Columns 1 plus 3 represent the total domestic demand for gas in Alberta. Column 1 includes the fuel and losses for distribution of Alberta's net sales of gas. Column 3 is the fuel requirements of AGTL for all gas transported in its system leaving the province

—Column 2 is the exports south from Alberta—Alberta and Southern and Westcoast via Kingsgate, British Columbia, and Canadian-Montana via Cardston and Aden, Alberta

—Column 4 is the total reprocessing shrinkage from Column 5, page 2

—Columns 5, 7 and 8 are the Canadian requirements excluding Alberta. They include fuel and losses associated with transmission and distribution outside Alberta. Column 8 is the NEB estimate of expansion markets in Quebec and the Maritimes.

—Column 6 is the Westcoast GL-41 licensed volumes.

—Column 9 is the TCPL, ICG Transmission Limited and Niagara licensed export volumes.

—Columns 2, 6 and 9, the export requirements, have been adjusted to reflect full make-up of the licensed volumes.

REPROCESSING SHRINKAGES

(Bcf/yr. @ 1000 Btu/cf)

Year	(1) Cochrane	(2) Empress	(3) Edmonton	(4) Waterton	(5) Total (1+2+3+4)
1979	52	84	29	11	176
1980	54	104	27	11	196
1981	54	104	27	11	196
1982	53	104	30	11	198
1983	54	104	30	11	199
1984	54	104	30	11	199
1985	54	105	31	11	201
1986	54	132	31	10	227
1987	54	132	29	9	224
1988	54	132	26	8	220
1989	54	132	15	7	208
1990	54	132	16	5	207
1991	54	132	17	4	207
1992	54	132	25	4	215
1993	54	132	26	4	216
1994	54	132	27	3	216
1995	54	132	28	3	217
1996	54	132	30	3	219
1997	54	132	30	3	219
1998	54	132	31	2	219
1999	54	132	31	2	219
2000	54	132	32	2	220
TOTAL	**1185**	**2689**	**598**	**146**	**4618**

—The forecast of reprocessing shrinkages at Cochrane, Empress and Edmonton were adopted from Dome based on expected plant capacities

—The forecast of shrinkage related to ethane extraction at Waterton was prepared by the Board

—The Empress forecast includes expansion of 27.5 Bcf/yr. commencing in 1986

CANADIAN GAS DELIVERABILITY FROM CONTROLLED RESERVES

(Bcf/yr. @ 1000 Btu/cf)

Year	(1) TCPL	(2) A&S	(3) Westcoast	(4) Westcoast GL-4	(5) Pan-Alberta	(6) Alberta Utilities Major	(7) Alberta Utilities Minor	(8) Canadian Montana	(9) Many Islands Pipelines	(10) Production East of Alberta	(11) Total
Remaining Reserves at 31 Dec. 1978	**22503**	**8317**	**7272**	**242**	**1252**	**5899**	**1271**	**326**	**636**	**1224**	**48942**
1979	1394	542	425	57	60	366	49	16	20	54	2982
1980	1380	542	448	57	61	376	42	15	20	53	2994
1981	1389	519	456	57	61	377	46	14	21	51	2991
1982	1445	513	458	57	58	378	44	12	24	50	3039
1983	1501	515	427	15	52	347	42	14	26	49	2987
1984	1400	503	396	0	47	320	41	12	29	46	2795
1985	1292	466	382	0	44	339	41	12	28	42	2646
1986	1209	434	367	0	40	311	40	13	25	45	2484
1987	1125	426	350	0	36	294	37	13	22	48	2351
1988	1090	384	324	0	34	273	32	13	19	42	2211
1989	979	320	298	0	31	252	28	9	17	38	1972
1990	885	322	245	0	22	236	25	11	15	35	1796
1991	811	300	193	0	22	222	22	10	14	31	1626
1992	732	284	184	0	22	218	20	9	12	29	1509
1993	666	246	166	0	22	205	18	8	11	27	1369
1994	600	211	146	0	20	192	15	7	10	23	1224
1995	515	159	143	0	18	176	14	6	9	23	1063
1996	449	142	130	0	16	159	12	6	8	21	943
1997	405	133	122	0	14	144	11	5	7	20	860
1998	351	120	114	0	13	129	10	4	6	19	767
1999	304	109	107	0	11	116	9	4	6	18	685
2000	264	99	101	0	10	104	8	4	5	17	611
TOTAL	**20184**	**7292**	**5980**	**242**	**714**	**5534**	**606**	**217**	**354**	**781**	**41903**
Total Remaining Reserves at 31 Dec. 2000	**2319**	**1025**	**1292**	**0**	**538**	**365**	**665**	**109**	**282**	**443**	**7039**

—NEB forecasts of production from contracted reserves for TCPL, A&S, Westcoast and Pan-Alberta are in Columns 1, 2, 3 and 5 respectively.
—The Westcoast forecast includes all gas in the Westcoast supply area (excepting supply for Licence GL-4).
—Westcoast GL-4 is at the annual authorized level until total licensed volumes have been produced
—Major and Minor Alberta utilities supply forecasts were adopted from the Polar Gas submission
—Canadian-Montana's supply forecast was adopted from its submission
—Many Islands Pipelines' forecast was adopted from the SPC submission
—Production East of Alberta includes the forecast of Saskatchewan production from the SPC submission and the Board's forecast of Ontario production
—Remaining reserves as at 31 December 1978 have been allocated on the basis of available information regarding controlled supplies.

GAS SUPPLY AVAILABLE TO MEET ALBERTA DEMAND

(Bcf/yr. @ 1000 Btu/cf)

Year	(1) Total Demand	(2) Alberta Supplies	(3) TCPL Alberta Supplies	(4) Deferred Supply	(5) Shallow Uncommitted Supply	(6) Non-Associated Uncommitted Supply	(7) Supply from B.E.R. Reserves	(8) Alberta Trend Supply	(9) Total (2+3+4+5 +6+7+8)	(10) Surplus (9 − 1)
1979	1170	1023	139	0	38	40	2	0	1242	72
1980	1220	1027	139	0	88	96	4	14	1369	149
1981	1215	1007	142	0	123	152	6	42	1472	257
1982	1217	990	145	0	136	212	8	90	1582	365
1983	1196	913	149	13	140	260	10	153	1638	443
1984	1195	850	155	16	135	296	13	224	1688	493
1985	1197	837	157	33	124	324	15	295	1785	588
1986	1111	764	160	37	117	348	17	358	1801	690
1987	994	731	161	35	109	364	19	416	1834	840
1988	998	661	159	30	104	376	21	471	1822	824
1989	927	565	150	27	97	384	23	524	1770	843
1990	935	580	141	24	90	379	25	575	1814	879
1991	937	540	136	23	84	370	27	620	1800	864
1992	929	517	130	22	80	356	29	657	1791	862
1993	949	461	125	35	76	335	30	685	1748	799
1994	922	410	121	34	68	312	32	705	1682	760
1995	937	340	112	34	63	289	33	720	1591	654
1996	947	304	106	33	60	265	34	731	1533	586
1997	956	278	102	54	58	242	35	738	1508	552
1998	965	247	97	82	52	220	36	741	1476	511
1999	974	222	93	81	48	201	37	741	1423	450
2000	983	199	89	79	43	192	38	738	1379	396
TOTAL	**22870**	**13468**	**2908**	**692**	**1933**	**6013**	**495**	**10238**	**35747**	**12877**

—Column 1 is the total Alberta demand including exports south from Alberta and is the sum of Columns 1 to 4 on page 1.
—Column 2 is the sum of the major and minor Alberta utilities forecast, the A&S forecast less A&S Columbia sales and Pan-Alberta contracted sales, the Westcoast GL-4 forecast and the Canadian-Montana forecast.
—Column 3 is the Board's estimate of TCPL's Alberta sales and the AGTL fuel and reprocessing shrinkages associated with TCPL's supply (Columns 3 and 4, page 6).
—Column 4 is the Board's estimate of supply from deferred reserves in Alberta
—Column 5 is the Board's estimate of supply from uncommitted shallow gas reserves in N.W. and S.E. Alberta
—Column 6 is the Board's estimate of supply from the remaining uncommitted gas reserves in Alberta.
—Column 7 is the Board's estimate of supply from ½ of the reserves beyond economic reach in Alberta
—Column 8 is the Board's forecast of deliverability from Alberta trend gas additions
—Column 10 is the volume of gas supply in excess of Alberta's total requirements

ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND

(Bcf/yr. @ 1000 Btu/cf)

Year	(1) Total Demand	(2) Westcoast Supply	(3) Pan-Alberta Supply	(4) A&S (Columbia) Sales	(5) B.C. Trend Supply	(6) Net B.C. Supply (2+3+4+5)	(7) Demand for Alberta Gas (1−6)
1979	481	425	39	5	0	469	13
1980	490	448	39	5	3	495	−5
1981	499	456	39	6	8	509	−10
1982	508	458	39	10	15	522	−14
1983	519	427	39	10	28	504	15
1984	533	396	39	13	47	495	38
1985	546	382	29	13	66	490	56
1986	551	367	39	13	84	503	48
1987	555	350	39	13	104	506	49
1988	561	324	39	13	123	499	62
1989	515	298	39	14	141	492	23
1990	367	245	0	14	157	416	−50
1991	320	193	0	14	172	379	−59
1992	276	184	0	14	186	384	−108
1993	288	166	0	15	198	379	−91
1994	299	146	0	15	209	370	−71
1995	312	143	0	15	217	375	−63
1996	324	130	0	15	222	367	−43
1997	338	122	0	15	225	362	−24
1998	352	114	0	16	225	355	−3
1999	368	107	0	16	222	345	23
2000	384	101	0	16	218	335	50
TOTAL	**9386**	**5980**	**419**	**280**	**2870**	**9549**	**−164**

—Column 1 is the total British Columbia demand obtained by adding the total domestic and export demands, Columns 5 and 6 from page 1.
—Column 2 is the NEB forecast of Westcoast gas supply from Column 3, page 3
—Column 3 is the Pan-Alberta firm contract with Westcoast. In 1985, the Pan-Alberta supplies including supplies available from A&S less Pan-Alberta's commitments east of Alberta are deficient overall.
—Column 4 is A&S's estimate of its sales to Columbia Natural Gas in British Columbia
—Column 5 is the NEB forecast of supply from trend additions in British Columbia
—Column 7 is the additional gas supply necessary to meet British Columbia total demand

ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA

(Bcf/yr. @ 1000 Btu/cf)

Year	(1) Total Demand	(2) TCPL Supply	(3) TCPL Alberta Sales	(4) AGTL Fuel and Reprocessing	(5) Many Islands Pipelines Supply	(6) Pan-Alberta Supply	(7) Production East of Alberta	(8) Saskatchewan Trend Supply	(9) Net East of Alberta Supply (2−3−4+5 +6+7+8)	(10) Demand for Alberta Gas (1−9)
1979	1351	1394	19	120	20	22	54	0	1351	0
1980	1337	1380	19	120	20	22	53	1	1337	0
1981	1342	1389	22	120	21	22	51	1	1342	0
1982	1398	1445	25	120	24	22	50	2	1398	0
1983	1452	1501	29	120	26	22	49	3	1452	0
1984	1520	1400	35	120	29	22	46	4	1346	174
1985	1588	1292	37	120	28	22	42	5	1232	356
1986	1623	1209	40	120	25	22	45	6	1147	476
1987	1669	1125	43	118	22	22	48	9	1065	604
1988	1712	1090	45	114	19	22	42	11	1025	687
1989	1748	979	48	102	17	22	38	14	920	827
1990	1735	885	50	91	15	22	35	16	831	904
1991	1693	811	53	83	14	22	31	18	760	933
1992	1684	732	56	74	12	22	29	20	684	1000
1993	1740	666	58	67	11	22	27	22	623	1117
1994	1802	600	61	60	10	20	23	24	556	1246
1995	1867	515	62	50	9	18	23	25	478	1389
1996	1925	449	63	43	8	16	21	27	415	1510
1997	1995	405	64	38	7	14	20	29	373	1622
1998	2071	351	65	32	6	13	19	30	322	1749
1999	2148	304	66	27	6	11	18	32	279	1869
2000	2230	264	67	22	5	10	17	34	241	1989
TOTAL	**37628**	**20184**	**1027**	**1881**	**354**	**432**	**781**	**333**	**19176**	**18452**

—Column 1 is the total demand for gas East of Alberta from Columns 7, 8 and 9, page 1
—Column 2 is the NEB forecast of supply from TCPL's contracted gas volumes (Column 1, page 3)
—Column 3 is the Board's estimate of TCPL's sales to Alberta utilities
—Column 4 is the NEB estimate of total Empress shrinkage and the AGTL fuel required to transport gas for East of Alberta use. The volumes are based on TCPL throughput
—Column 5 is the Many Islands Pipelines' forecast of production from Column 9, page 3
—Column 6 is the projected supply of Pan-Alberta to meet its East of Alberta commitments
—Column 7 is the forecast of production East of Alberta (Column 10, page 3)
—Column 8 is the NEB forecast of supply from trend additions in Saskatchewan.
—Column 10 is the additional gas supply necessary to meet total demand East of Alberta

ALLOCATION OF GAS SURPLUS TO ALBERTA DEMAND

(Bcf/yr. @ 1000 Btu/cf))

	SURPLUS SUPPLIES			DEMAND FOR ALBERTA SURPLUS		ALLOCATION OF SURPLUS		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	**Alberta Surplus**	**Supply from Temporary Surplus**	**Total**	**East of Alberta**	**British Columbia**	**East of Alberta**	**British Columbia**	**Temporary Surplus Available for later use**
1979	72	0	72	0	13	0	13	59
1980	149	0	154	0	−5	0	0	154
1981	257	0	267	0	−10	0	0	267
1982	365	0	379	0	−14	0	0	379
1983	443	0	443	0	15	0	15	428
1984	493	0	493	174	38	174	38	281
1985	588	0	588	356	56	356	56	177
1986	690	0	690	476	48	476	48	166
1987	840	0	840	604	49	604	49	187
1988	824	0	824	687	62	687	62	75
1989	843	8	851	827	23	827	23	0
1990	879	0	929	904	−50	904	0	25
1991	864	10	933	933	−59	933	0	0
1992	862	30	1000	1000	−108	1000	0	0
1993	799	110	1000	1117	−91	1000	0	0
1994	760	110	941	1246	−71	941	0	0
1995	654	110	827	1389	−63	827	0	0
1996	586	110	739	1510	−43	739	0	0
1997	552	110	686	1622	−24	686	0	0
1998	511	110	624	1749	−3	624	0	0
1999	450	110	560	1869	23	553	7	0
2000	396	110	506	1989	50	494	12	0
TOTAL	**12877**	**927**	**14343**	**18452**	**−164**	**11824**	**323**	**2196**

—Column 1 is the total projected supply of gas surplus to Alberta's requirements from Column 10, page 4.

—Additional gas was assumed to flow to meet British Columbia deficiencies when required

—After supplying British Columbia and East of Alberta as shown in Columns 6 and 7, there remain volumes of gas which provide a temporary overall surplus to Canadian Demand. These volumes, shown in Column 8, are assumed not to be produced and are converted to a forecast of deliverability starting in 1989 as shown in Column 2. The temporary surplus in British Columbia is also included in Columns 2 and 3 and is assumed to be available East of Alberta if required

—The total surplus supply, Column 3, is allocated between British Columbia and East of Alberta based upon the proportion of the unsatisfied demand which is attributable to each of these regions.

ADJUSTMENTS TO ALBERTA UNCOMMITTED AND TREND SUPPLIES

(Bcf/yr. @ 1000 Bcf/cf)

			UNADJUSTED		ADJUSTED	
	(1)	(2)	(3)	(4)	(5)	(6)
Year	Temporary Surplus Supply	Deferred Deliverability	Alberta Uncommitted	Alberta Trend	Alberta Uncommitted	Alberta Trend
1979	59	0	80	0	21	0
1980	154	0	188	14	49	0
1981	267	0	281	42	56	0
1982	379	0	356	90	68	0
1983	428	0	410	153	135	0
1984	281	0	444	224	387	0
1985	177	0	463	295	463	118
1986	166	0	482	358	482	192
1987	187	0	492	416	492	229
1988	75	0	501	471	501	396
1989	0	8	504	524	504	532
1990	25	0	494	575	494	550
1991	0	10	481	620	481	630
1992	0	30	465	657	465	687
1993	0	110	441	685	441	795
1994	0	110	412	705	412	815
1995	0	110	385	720	385	830
1996	0	110	359	731	359	841
1997	0	110	335	738	335	848
1998	0	110	308	741	308	851
1999	0	110	286	741	286	851
2000	0	110	273	738	273	848
TOTAL	**2196**	**927**	**8441**	**10238**	**7397**	**10013**

—Column 1 is the temporary surplus Alberta supply taken from Column 8, page 7

—Column 2 is the deliverability, commencing in 1989, attributable to the volumes indicated to be surplus in Column 1 and assumed not to be produced in the period indicated in Column 1

—The figures in Columns 1 and 2 were used to adjust the NEB forecasts of supply from uncommitted and trend gas in Alberta.

—The Board judged that the bulk of the adjustments necessary would be made to the trend gas forecast, Column 4, which is taken from Column 8, page 4. Any further adjustment was made to the uncommitted supply forecast, Column 3, which is the sum of Columns 5, 6 and 7 from page 4

—The adjusted forecasts to be used in the total supply-demand balance are in Columns 5 and 6

BRITISH COLUMBIA SUPPLY-DEMAND BALANCE

(Bcf/yr. @ 1000 Btu/cf)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	British Columbia Demand	Huntingdon Export	Total (1+2)	British Columbia Net Supply	Alberta Surplus to British Columbia	Total (4+5)	Deficiency (3−6)
1979	178	303	481	469	13	481	0
1980	186	304	490	495	−5	490	0
1981	196	303	499	509	−10	499	0
1982	205	303	508	522	−14	508	0
1983	216	303	519	504	15	519	0
1984	229	304	533	495	38	533	0
1985	243	303	546	490	56	546	0
1986	248	303	551	503	48	551	0
1987	252	303	555	506	49	555	0
1988	257	304	561	499	62	561	0
1989	263	252	515	492	23	515	0
1990	257	110	367	416	−50	367	0
1991	265	55	320	379	−59	320	0
1992	276	0	276	384	−108	276	0
1993	288	0	288	379	−91	288	0
1994	299	0	299	370	−71	299	0
1995	312	0	312	375	−63	312	0
1996	324	0	324	367	−43	324	0
1997	338	0	338	362	−24	338	0
1998	352	0	352	355	−3	352	0
1999	368	0	368	345	7	352	16
2000	384	0	384	335	12	347	37
TOTAL	**5936**	**3450**	**9386**	**9549**	**−217**	**9333**	**53**

—Column 1 is taken from Column 5, page 1
—Column 2 is taken from Column 6, page 1
—Column 4 is taken from Column 6, page 5.
—Column 5 is taken from Column 7, page 7, including British Columbia surplus supplies from Column 5, page 7, which were assumed to be available for markets East of Alberta.

EAST OF ALBERTA SUPPLY-DEMAND BALANCE

(Bcf/yr. @ 1000 Btu/cf)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	Canadian	Export	Total (1+2)	Net Supply East of Alberta	Surplus to East of Alberta	Total (4+5)	Deficiency (3−6)
1979	1038	313	1351	1351	0	1351	0
1980	1066	271	1337	1337	0	1337	0
1981	1109	233	1342	1342	0	1342	0
1982	1165	233	1398	1398	0	1398	0
1983	1219	233	1452	1452	0	1452	0
1984	1287	233	1520	1346	174	1520	0
1985	1355	233	1588	1232	356	1588	0
1986	1397	226	1623	1147	476	1623	0
1987	1443	226	1669	1065	604	1669	0
1988	1485	227	1712	1025	687	1712	0
1989	1533	215	1748	920	827	1748	0
1990	1585	150	1735	831	904	1735	0
1991	1624	69	1693	760	933	1693	0
1992	1676	8	1684	684	1000	1684	0
1993	1732	8	1740	623	1000	1623	117
1994	1794	8	1802	556	941	1497	305
1995	1861	6	1867	478	827	1305	562
1996	1925	0	1925	415	739	1154	771
1997	1995	0	1995	373	686	1059	936
1998	2071	0	2071	322	624	946	1125
1999	2148	0	2148	279	553	831	1317
2000	2230	0	2230	241	494	735	1495
TOTAL	34738	2890	37628	19176	11824	31000	6628

—Column 1 is taken from Columns 7 and 8, page 1
—Column 2 is taken from Column 9, page 1
—Column 4 is taken from Column 9, page 6
—Column 5 is taken from Column 6, page 7

TOTAL CANADIAN SUPPLY-DEMAND BALANCE

(Bcf/yr. @ 1000 Btu/cf))

	DEMAND			SUPPLY					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	**Domestic**	**Export**	**Total (1+2)**	**Total Controlled**	**Alberta Uncommitted**	**Alberta Deferred**	**Trend Supply**	**Total (4+5+6+7)**	**Deficiency (3−8)**
Remaining Reserves at 31 December 1978				**48942**	**12938**	**4220**	**0**	**66100**	
Total Including Trend to 31 December 2000							**33700**	**99800**	
1979	1870	1132	3002	2982	21	0	0	3003	0
1980	1960	1087	3047	2994	49	0	4	3047	0
1981	2033	1023	3056	2991	56	0	9	3056	0
1982	2114	1008	3122	3039	68	0	17	3123	0
1983	2205	962	3166	2987	135	13	31	3166	0
1984	2300	948	3248	2795	387	16	51	3248	0
1985	2405	926	3330	2646	463	33	189	3331	0
1986	2470	815	3285	2484	482	37	282	3285	0
1987	2525	693	3218	2351	492	35	342	3219	0
1988	2592	679	3271	2211	501	30	530	3272	0
1989	2643	547	3190	1972	504	27	687	3190	0
1990	2697	340	3037	1796	494	24	723	3037	0
1991	2753	196	2949	1626	481	23	820	2949	0
1992	2835	54	2889	1509	465	22	893	2889	0
1993	2931	46	2976	1369	441	35	1015	2859	117
1994	3015	8	3023	1224	412	34	1048	2718	305
1995	3110	6	3116	1063	385	34	1072	2554	562
1996	3196	0	3196	943	359	33	1090	2424	771
1997	3289	0	3289	860	335	54	1102	2352	936
1998	3388	0	3388	767	308	82	1106	2263	1125
1999	3490	0	3490	685	286	81	1105	2157	1333
2000	3597	0	3597	611	273	79	1100	2064	1533
TOTAL	**59416**	**10468**	**69884**	**41903**	**7397**	**692**	**13216**	**63207**	**6677**
Remaining Reserves at 31 December 2000				**7039**	**5541**	**3528**	**20484**	**36593**	

—Figures may not balance due to rounding

—Board estimates of the remaining marketable gas reserves at 31 December, 1978 which support the NEB forecasts of supply are shown at the top of Columns 4 to 8. Column 5 includes all of the 1978 Alberta reserves addition.

—The total trend additions from 1 January, 1979 to 31 December 2000 are 33.7 Tcf and support the total deliverability from trend gas in Column 7.

—Columns 1 to 6 inclusive are taken from Columns 10, 11 and 12, page 1; Column 11, page 3; Column 5, page 8 and Column 4, page 4 respectively

—Column 7 is the sum of Columns 5, page 5; Column 8, page 6 and Column 6, page 8

—The total deficiency in Column 9 includes deficiencies in British Columbia and East of Alberta as shown in Column 7, page 9 and Column 7, page 10 respectively

NATURAL GAS EXPORTS BY AREA FOR EXISTING LICENCES

(Bcf/yr. @ 1000 Btu/cf)

		Licence Number	Total Remaining	Annual 1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
SOUTH FROM ALBERTA	A&S	GL-3*	1245.2	171.1	168.3	156.6	156.6	156.6	156.6	156.6	122.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-16*	781.1	84.4	84.6	84.4	78.0	76.5	76.5	76.5	76.5	76.5	67.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-24*	1130.8	88.0	88.3	81.9	79.6	79.6	79.6	79.6	79.6	79.6	79.6	79.6	79.6	72.8	45.6	37.7	0.0	0.0
		GL-35*	484.5	76.5	75.4	69.0	69.0	69.0	69.0	56.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CMPL	GL-5*	86.1	15.8	15.9	15.8	12.2	10.7	10.7	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-17*	75.3	9.9	9.5	9.5	7.5	7.5	7.5	7.5	7.5	7.5	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-25*	55.6	9.0	9.0	9.0	8.9	7.5	7.5	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-36*	27.6	4.5	4.5	4.3	3.7	3.7	3.7	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WTCL	GL-4*	166.8	56.7	56.9	53.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WTCL	Makeup**	74.8	0.0	0.0	3.4	56.7	14.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TOTAL		4127.8	515.9	512.3	487.3	472.2	425.8	411.1	389.8	286.0	163.6	148.5	79.6	79.6	72.8	45.6	37.7	0.0	0.0
BRITISH COLUMBIA	WTCL	GL-41*	3285.3	303.0	303.9	303.0	303.0	303.0	303.9	303.0	303.0	303.0	303.9	252.4	0.0	0.0	0.0	0.0	0.0	0.0
	WTCL	Makeup**	164.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	109.8	54.9	0.0	0.0	0.0	0.0
	TOTAL		3449.9	303.0	303.9	303.0	303.0	303.0	303.9	303.0	303.0	303.0	303.9	252.4	109.8	54.9	0.0	0.0	0.0	0.0
EAST OF ALBERTA	ICG	GL-28*	5.9	1.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.0
		GL-29*	133.5	11.7	8.8	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	6.3
	NGT	GL-6	44.7	6.5	6.4	6.4	6.4	6.4	6.4	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TCPL	GL-1	110.0	73.6	36.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-18*	590.2	54.8	54.5	54.4	54.4	54.4	54.5	54.4	54.4	54.4	54.5	45.3	0.0	0.0	0.0	0.0	0.0	0.0
		GL-19	68.2	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	4.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-20*	435.1	34.1	34.0	33.9	33.9	33.9	34.0	33.9	33.9	33.9	34.0	33.9	33.9	28.2	0.0	0.0	0.0	0.0
		GL-37	835.8	71.1	70.7	70.5	70.5	70.5	70.7	70.5	70.5	70.5	70.7	70.5	58.7	0.0	0.0	0.0	0.0	0.0
		GL-38	213.4	18.2	18.1	18.0	18.0	18.0	18.1	18.0	18.0	18.0	18.1	18.0	15.0	0.0	0.0	0.0	0.0	0.0
		GL-39	30.7	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.2	0.0	0.0	0.0	0.0	0.0
		GL-43	218.3	16.9	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	0.0	0.0	0.0	0.0
	TCPL	Makeup**	204.3	15.8	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	0.0	0.0	0.0	0.0
	TOTAL		2890.1	312.9	270.7	232.7	232.7	232.7	233.2	232.5	226.3	226.3	226.7	214.7	150.2	68.6	7.9	7.9	7.9	6.3
CANADA	**TOTAL**		**10467.8**	**1131.8**	**1086.9**	**1023.0**	**1007.9**	**961.5**	**948.1**	**925.3**	**815.3**	**692.8**	**679.2**	**546.7**	**339.6**	**196.3**	**53.5**	**45.6**	**7.9**	**6.3**

* Including maximum annual makeup of volumes not taken in prior years, as permitted by existing annual averaging conditions in the licence.

** Assuming that the licences will be conditioned to permit the makeup of volumes not taken in prior years
— In the case of Westcoast, makeup volumes are assumed to be exported at the end of the licence term
— In the case of TransCanada, makeup volumes are assumed to be averaged over the licence term.

Abbreviations

TCPL — TransCanada	CMPL — Canadian-Montana
A&S — Alberta & Southern	WTCL — Westcoast
NGT — Niagara	ICG — ICG Transmission Ltd

METRIC

APPENDICES

INITIAL ESTABLISHED RESERVES OF MARKETABLE NATURAL GAS

NEB Estimates Significantly Different From Estimates of Provincial Agencies 31–12–77

BRITISH COLUMBIA

Field & Pool or Pool Group	NEB (10^6m^3)	Provincial Agency[1)] (10^6m^3)
BEG		
Baldonnel A,B & C	2 663	3 654
CABIN		
Slave Point A,B & C	1 303	3 116
CLARKE LAKE		
Slave Point A	31 161	35 240
KOTCHO LAKE		
Slave Point A, B & C	1 473	4 249
KOTCHO LAKE EAST		
Slave Point A, B & C	1 501	4 646
LAPRISE CREEK		
Baldonnel	16 232	21 784
NIG CREEK		
Baldonnel A	10 708	13 427
PETITOT RIVER		
Slave Point	850	1 898
SIERRA		
Pine Point A & B	23 710	16 260
VELMA		
Gething	1 303	2 719
YOYO		
Slave Point/Pine Point	24 418	37 138

ALBERTA

Field & Pool or Pool Group	NEB (10^6m^3)	Provincial Agency (10^6m^3)
BENJAMIN		
Rundle A & B	4 278	4 929
BRAZEAU RIVER		
Elkton–Shunda A & B	43 823	42 265
CRAIGEND		
Viking C	2 436	4 221
CROSSFIELD		
Wabamun A	16 289	14 079
CROSSFIELD EAST		
Wabamun A	16 147	14 079
DUNVEGAN		
Debolt A,B,C & D	24 277	25 353
EDSON		
Ekiton A & Shunda A & B	45 523	48 186
FERRYBANK		
Belly River C	906	1 841
GHOST PINE		
Upper Mannville C associated, G,H, P & U	3 683	4 504
Upper Mannville Q Associated	2 125	2 946
HARMATTAN EAST		
Rundle associated	21 246	24 787
HOMEGLEN–RIMBEY		
D–3 associated & solution	24 928	23 172
HOTCHKISS		
Bluesky A,E & other	1 473	708
Debolt A & B, Shunda A	3 853	2 861
IRRICANA		
Wabamun A	1 615	397
JUMPING POUND WEST		
Rundle C	5 637	10 708
LEISMER		
Clearwater A	7 195	5 637
LONE PINE CREEK		
Wabamun A	7 847	10 425
MARLBORO		
Leduc A	1 841	2 804
MARTEN HILLS		
Wabiskaw A & Wabamun A,C & other	27 393	25 495
MORLEY		
Rundle	1 190	340
NEVIS		
Blairmore A & Mannville other	453	1 615
PADDLE RIVER		
Jurassic–Detrital–Rundle	8 498	9 858
RICINUS WEST		
D–3A	22 549	23 937
SWAN HILLS		
Beaverhill Lake A & B solution	7 903	8 725
SWAN HILLS SOUTH		
Beaverhill Lake A & B solution	5 156	6 487
TWINING		
Lower Mannville A & Rundle A associated & solution	6 940	8 158
WESTEROSE SOUTH		
D–3A	40 395	38 894
MILK RIVER		
Pool No. 1	131 554	140 789
MEDICINE HAT		
Pools No. 1, 3 & 4	101 924	100 252

Field & Pool or Pool Group	10^6m^3	
2ND WHITE SPECKS		
Pool No. 1	35 240	33 795

[1]data for British Columbia from British Columbia Ministry of Mines and Petroleum Resources Report, Hydrocarbon and By–Product Reserves in British Columbia 31 December 1977.
Data for Alberta from AERCB Report 78–18.
Metric conversion by NEB.

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	1662	1796	2136	2402	3032
A & S	1581	1707	1951	2228	2910
Consolidated	1594	1725	–	–	–
Dome	1572	1686	1957	2209	2769
Gulf	1577	1736	2126	2545	3283
Home Oil	1888	2064	2383	2625	3103
Imperial	1580	1690	2140	2499	3094
IPAC	1606	1764	2081	2339	2883
Norcen	1637	1764	1986	2170	2554
PanCanadian	1772	1963	2245	2501	3081
Polar Gas	1576	1710	2025	2392	3134
ProGas	1598	1722	1942	2189	2618
Shell	1575	1677	1971	2214	2698
TransCanada	1597	1693	1900	2141	2703
NEB	1588	1708	2016	2251	3051

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
ONTARIO
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	776	830	983	1128	1456
A & S	726	750	837	996	1246
Consolidated	708	726	–	–	–
Dome	696	713	826	929	1174
Gulf	726	760	904	1059	1347
Imperial	740	810	1027	1177	1359
IPAC	702	739	874	992	1234
Norcen	716	723	811	883	1050
NCGas	716	723	811	882	1050
PanCanadian	713	720	847	1004	1344
Polar Gas	–	759	896	1029	1302
ProGas	707	738	817	918	1092
Shell	718	753	881	997	1264
Sun	729	783	923	1087	–
TransCanada	708	697	768	891	1237
Union Gas	–	760	905	1047	1366
NEB	720	751	866	976	1354

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
QUEBEC
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	85	89	103	114	136
A & S	93	104	131	158	238
Consolidated	91	100	–	–	–
Dome	90	116	148	182	249
Gaz Métropolitain	96	99	123	147	199
Quebec	–	–	–	96	–
Gulf	90	96	123	156	223
Imperial	90	95	123	153	195
IPAC	104	115	149	189	262
Norcen	96	98	118	124	172
PanCanadian	100	123	161	204	301
Polar Gas	–	123	160	202	302
ProGas	88	95	114	135	178
Shell	90	94	111	129	165
Sun	90	97	134	163	–
TransCanada	92	98	123	146	206
NEB	90	101	118	141	213

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
MANITOBA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	72	77	91	105	140
A & S	73	75	82	94	122
Consolidated	65	69	–	–	–
Dome	67	72	81	94	116
Manitoba	69	75	91	103	129
Gulf	69	74	89	101	120
Imperial	–	–	–	–	–
IPAC	75	81	93	109	143
Norcen	74	78	83	94	116
PanCanadian	67	74	85	101	137
Polar Gas	–	74	84	100	140
ProGas	67	74	84	95	114
Shell	67	71	78	83	96
TransCanada	69	69	76	82	95
NEB	69	74	84	95	125

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
SASKATCHEWAN
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	110	116	139	165	221
A & S	105	108	119	138	192
Consolidated	104	109	–	–	–
Dome	111	115	127	137	157
Gulf	100	105	121	139	175
Imperial	–	–	–	–	–
IPAC	100	105	123	148	204
Norcen	111	117	124	134	154
PanCanadian	111	111	129	151	206
Polar Gas	–	123	153	186	264
ProGas	100	103	114	121	137
SPC	102	100	108	115	128
Shell	113	117	125	131	153
TransCanada	103	100	113	127	163
NEB	102	109	119	135	213

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
BRITISH COLUMBIA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	158	170	219	257	343
A & S	158	174	202	236	323
B.C. Hydro	151	189	233	270	348
Consolidated	152	163	–	–	–
Dome	153	163	208	245	326
Gulf	152	192	234	298	373
Imperial	155	172	253	303	379
IPAC	155	168	201	242	330
Norcen	161	175	231	270	361
PanCanadian	179	196	232	260	366
Polar Gas	–	176	225	263	335
ProGas	153	163	200	237	311
British Columbia	158	168	–	226*	–
Shell	154	165	202	232	300
TransCanada	151	161	208	237	307
Westcoast	162	185	230	282	362
NEB	151	167	225	252	380

* Year 1992

TOTAL NET SALES OF NATURAL GAS – (EXISTING MARKETS)
ALBERTA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AERCB	523	636	683	723	729
AGTL	462	514	599	634	735
A & S	426	497	579	641	789
Consolidated	475	559	–	–	–
Dome	456	507	568	623	749
Gulf	441	508	656	790	1045
Home*	612	728	802	780	791
Imperial	–	–	–	–	–
IPAC	469	556	640	661	711
Norcen	479	573	618	665	701
PanCanadian**	601	738	791	780	728
Polar Gas	–	453	506	612	791
ProGas	483	548	612	683	786
Shell	433	479	575	644	720
TransCanada	475	567	613	658	695
NEB	458	509	605	653	766

* Includes pipeline fuel and losses, shrinkage and ethane feedstock.
** Includes pipeline fuel and losses.

NET SALES OF NATURAL GAS – (EXISTING MARKETS) RESIDENTIAL
CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	343	369	444	515	651
Consolidated	346	360*	–	–	–
Dome	354	374	427	484	597
Gulf	351	374	438	491	553
Imperial	437	506	620	712	836
IPAC	381	403	460	527	642
Polar Gas	–	362	414	477	601
ProGas	361	385	438	486	579
Shell	429	449	507	527	584
TransCanada	364	373	402	418	458
NEB	356	369	417	464	575

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) COMMERCIAL CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	330	362	449	533	678
Consolidated	322	342*	–	–	–
Dome	335	356	417	493	646
Gulf	353	391	488	580	734
Imperial	296	311	389	449	555
IPAC	332	364	438	517	662
Polar Gas	–	387	475	577	768
ProGas	347	372	448	519	624
Shell	262	277	317	348	393
TransCanada	348	371	419	443	542
NEB	354	386	466	526	667

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) PETROCHEMICALS CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	174	192	223	224	220
Consolidated	–	–	–	–	–
Dome	187	204	233	252	301
Gulf	130	166	244	291	438
Imperial	84	79	99	116	165
IPAC	–	–	–	–	–
Polar Gas	–	166	194	214	215
ProGas	158	179	211	237	264
Shell	90	93	116	129	129
TransCanada	215	285	288	292	288
NEB	174	186	229	250	270

NET SALES OF NATURAL GAS – (EXISTING MARKETS) RESIDENTIAL/COMMERCIAL CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	673	731	893	1047	1329
Consolidated	667	701*	–	–	–
Dome	690	731	843	977	1243
Gulf	704	766	925	1070	1287
Imperial	733	817	1009	1161	1391
IPAC	712	767	899	1044	1305
Polar Gas	–	749	889	1054	1369
ProGas	708	757	886	1005	1203
Shell	691	727	826	875	978
TransCanada	712	745	820	861	1000
NEB	711	755	883	990	1241

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) INDUSTRIAL CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	644	687	822	946	1291
Consolidated	927	1024*	–	–	–
Dome	581	621	738	832	1063
Gulf	603	649	820	1024	1416
Imperial	651	687	921	1111	1512
IPAC	819	935	1126	1237	1519
Polar Gas	–	716	865	1045	1465
ProGas	646	690	778	894	1114
Shell	664	740	910	1095	1480
TransCanada	587	610	729	932	1359
NEB	578	635	756	860	1379

* Includes gas expansion

NET SALES OF NATURAL GAS – (EXISTING MARKETS) THERMAL GENERATION CANADA
Comparison of Forecasts
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	172	188	199	187	193
Consolidated	–	–	–	–	–
Dome	116	130	143	150	163
Gulf	138	155	137	158	142
Imperial	112	107	111	112	26
IPAC	75	63	56	58	60
Polar Gas	–	79	77	79	85
ProGas	85	96	66	53	37
Shell	131	117	119	116	113
TransCanada	82	54	63	56	56
NEB	127	133	149	151	161

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Canada
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	355.9	396.2	416.5	463.6	574.5
Commercial	354.7	385.9	465.8	526.7	666.5
Petrochemical	173.6	185.9	229.1	250.2	269.5
Other Industrial	578.0	634.4	756.0	859.9	1379.1
Thermal Electric Generation(1)	126.4	133.1	148.8	150.4	161.3
Total Net Sales	1588.7	1708.5	2016.1	2250.8	3050.8

(1) Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Manitoba
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	24.8	25.6	27.4	29.8	34.6
Commercial	21.6	23.9	27.8	30.9	38.4
Petrochemical	3.7	3.7	3.7	3.7	3.7
Other Industrial	17.7	20.0	24.5	29.3	48.6
Thermal Electric Generation(1)	0.2	0.2	0.4	0.6	1.1
Total Net Sales	68.0	73.5	83.8	94.4	125.9

(1) Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Quebec
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	19.2	20.5	22.7	26.9	36.4
Commercial	16.3	18.9	23.3	28.4	39.3
Petrochemical	–	–	–	–	–
Other Industrial	54.3	61.5	71.8	86.0	137.3
Thermal Electric Generation(1)	–	–	–	–	–
Total Net Sales	89.9	100.8	117.8	141.2	213.0

(1) Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Saskatchewan
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	30.1	30.9	33.2	36.9	43.7
Commercial	10.0	12.9	14.3	15.3	17.4
Petrochemical	–	–	–	–	–
Other Industrial	53.9	57.7	68.0	78.6	147.6
Thermal Electric Generation(1)	7.9	6.6	3.7	4.1	3.9
Total Net Sales	101.9	108.1	119.3	134.9	212.6

(1) Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Ontario
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	146.6	154.9	179.2	201.0	256.0
Commercial	177.0	190.9	239.3	273.0	348.4
Petrochemical	30.6	33.7	33.7	34.8	34.8
Other Industrial	311.1	328.6	376.7	425.8	662.5
Thermal Electric Generation(1)	54.7	42.2	37.2	41.7	52.5
Total Net Sales	720.0	750.4	866.2	975.9	1354.2

(1) Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – Alberta
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	90.0	89.0	96.7	104.9	125.1
Commercial	91.9	98.6	109.8	117.8	142.8
Petrochemical	134.6	143.7	186.9	206.9	226.2
Other Industrial	84.2	101.3	134.7	142.2	209.1
Thermal Electric Generation(1)	57.6	76.2	77.0	80.5	62.0
Total Net Sales	458.1	509.0	605.0	652.3	765.2

(1) Includes generation of electricity by industry as well as utilities

NET SALES OF NATURAL GAS – (EXISTING MARKETS)
NEB Forecast – British Columbia
(10^{15} joules)

	1978	1980	1985	1990	2000
Residential	45.3	48.1	57.3	64.1	79.1
Commercial	37.9	40.8	51.3	61.4	80.2
Petrochemical	4.7	4.7	4.7	4.7	4.7
Other Industrial	56.9	65.3	80.3	98.2	173.8
Thermal Electric Generation(1)	6.1	7.7	30.6	23.9	41.8
Total Net Sales	150.8	166.6	224.1	252.4	379.6

(1) Includes generation of electricity by industry as well as utilities

EXPANSION VOLUMES OF NATURAL GAS BY SECTOR – QUEBEC
Comparison of Estimates
(10^{15} joules)

	1980	1985	1990	1995	2000
RESIDENTIAL					
Dome	1.1	12.7	15.2	16.3	17.3
Home(1)	4	14	19	23	–
Imperial	0	15	21	28	36
IPAC Res./Com.	1	8	18	35	37
Norcen – Gaz Métro moderate penetration	0.2	2.6	10.0	15.7	20.2
ultimate penetration	0.4	18.1	24.3	32.7	38.0
Q&M	2.1	34.7	59.4	86.2	112.5
Shell(2)	4.9	23.7	36.1	60.5	62.2
Sun(3)	3.4	25.3	41.6	56.6	–
TCPL(4)	0	11	40	49	58
NEB(4)	3.8	20.1	32.5	41.7	44.1
COMMERCIAL					
Dome	0	10.2	12.3	13.2	13.5
Home(1)	9	24	35	46	–
Imperial	0	2	3	5	9
IPAC	–	–	–	–	–
Norcen – Gaz Métro moderate penetration	0.1	0.7	5.0	8.2	11.2
ultimate penetration	0.3	11.9	15.1	20.0	23.4
Q&M	1.8	27.1	46.2	66.9	87.2
Shell(2)	4.3	18.8	31.5	47.8	49.4
Sun(3)	5.1	24.6	44.8	73.9	–
TCPL(4)	0	13	38	47	53
NEB(4)	3.7	21.6	36.9	48.9	56.6

EXPANSION VOLUMES OF NATURAL GAS BY SECTOR – QUEBEC (Cont'd)
Comparison of Estimates
(10^{15} joules)

	1980	1985	1990	1995	2000
INDUSTRIAL					
Dome	1.2	52.9	55.3	59.6	62.3
Home(1)	21	46	63	84	–
Imperial	3	38	43	46	52
IPAC	1	53	55	60	63
Norcen – Gaz Métro moderate penetration	7.9	16.1	51.8	54.0	60.9
ultimate penetration	7.9	69.0	123.4	134.5	149.8
Q&M	6.2	71.5	108.8	146.9	171.0
Shell(2)	8.4	28.2	47.1	77.0	97.3
Sun(3)	13.5	76.9	90.6	103.2	–
TCPL(4)	14	79	141	134	146
NEB(4)	7.6	40.5	69.6	84.2	98.9
TOTAL NET SALES					
Dome	2.2	75.8	82.6	89.1	93.2
Home(1)	35	84	117	154	–
Imperial	3	55	67	80	97
IPAC	1	61	73	95	100
Norcen – Gaz Métro moderate penetration	8.2	19.5	66.8	77.9	92.3
ultimate penetration	8.6	99.0	162.7	187.2	211.1
ProGas(4)	28	74	100	111	119
Q&M	10.1	133.3	214.4	299.9	370.7
Shell(2)	17.6	70.7	114.7	185.3	209.0
Sun(3)	21.9	126.8	177.0	233.8	–
TCPL(4)	14	102	219	230	256
NEB(4)	15.1	82.3	139.0	174.8	199.6

Notes: (1) Adopted TransCanada submission to the 1978 Oil Inquiry — Exhibit 1722-9-3, Chapter IX, Table P. 10 Case II.
(2) Starting year, 1982.
(3) Re-adopted Hycarb study to 1978 Oil Inquiry, tables 5 to 7.
(4) Starting year, 1981.

EXPANSION VOLUMES OF NATURAL GAS BY SECTOR – ATLANTIC
Comparison of Estimates
(10^{15} joules)

	1981	1985	1990	1995	2000
RESIDENTIAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	0.9	3.1	7.3	11.4	–
Q&M	0.1	4.2	9.1	13.6	18.2
NEB(3)	0.9	4.0	7.7	10.8	11.6
COMMERCIAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	0.7	1.7	7.0	12.5	–
Q&M	0.1	3.0	6.3	9.5	12.9
NEB(3)	0.7	3.2	6.5	9.2	10.9
INDUSTRIAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	17.0	45.2	51.3	54.9	–
Q&M	0.5	10.1	21.4	34.8	40.4
NEB(3)	12.4	23.0	33.3	41.4	46.1
THERMAL					
IPAC(1)	–	–	–	–	–
Nova Scotia(2)	13.0	17.1	5.4	2.4	–
Q&M	3.2	18.5	10.3	13.8	17.3
NEB(3)	3.1	14.2	5.7	0	0
TOTAL NET SALES					
IPAC(1)	1	7	19	34	36
Nova Scotia(2)	30.0	67.3	70.8	81.3	–
Q&M	3.9	36.0	47.2	71.7	89.0
NEB(3)	17.2	44.4	53.3	61.4	68.6

(1) Starting year 1983.
(2) Starting year 1982 for Industrial and Thermal and 1983 for Residential and Commercial
(3) Starting year 1982.

ESTIMATES OF NATURAL GAS NET SALES INCLUDING GAS EXPANSION – QUEBEC
Comparison of Estimates
(10^{15} joules)

	1980	1985	1990	1995	2000
RESIDENTIAL					
AGTL(1)	21.5	59.9	89.2	121.8	153.3
Dome	23.2	40.9	48.9	55.9	63.0
Home(2)	26	37	42	47	–
Imperial	21	45	77	107	117
IPAC Res/Con(5)	44.0	61.1	85.6	117.4	133.7
Norcen – Gaz Métro					
moderate penetration	21.6	25.2	28.6	35.1	39.4
ultimate penetration	21.8	40.7	42.8	52.1	57.2
Q&M	19.9	58.2	87.7	119.5	150.8
Shell(3)	25.7	46.7	60.9	87.0	89.2
Sun(4)	21.7	45.8	63.2	79.1	–
TCPL(5)	21	34	64	74	84
NEB(5)	24.5	42.8	59.4	73.2	80.5
COMMERCIAL					
AGTL(1)	17.8	48.0	71.3	96.4	121.2
Dome	19.0	33.5	40.2	45.9	51.7
Home(2)	27	46	61	77	–
Imperial	24	33	35	38	49
IPAC(5)	–	–	–	–	–
Norcen – Gaz Métro					
moderate penetration	15.5	18.4	20.1	24.5	27.2
ultimate penetration	15.7	29.5	30.3	36.3	39.4
Q&M	16.5	46.4	69.6	94.3	118.6
Shell(3)	21.2	36.6	50.8	68.3	71.0
Sun(4)	20.9	43.0	64.8	95.0	–
TCPL(5)	16	31	57	69	75
NEB(5)	23.2	44.9	65.3	82.4	96.0

ESTIMATES OF NATURAL GAS NET SALES INCLUDING GAS EXPANSION – QUEBEC
(Cont'd)
Comparison of Estimates
(10^{15} joules)

	1980	1985	1990	1995	2000
INDUSTRIAL					
AGTL(1)	59.4	129.0	167.7	205.0	231.9
Dome	75.6	149.2	175.8	204.3	227.3
Home(2)	93	129	159	194	–
Imperial	53	100	109	116	127
IPAC(5)	81.7	149.0	175.4	204.8	228.2
Norcen – Gaz Métro					
moderate penetration	69.1	93.7	142.9	166.9	197.8
ultimate penetration	69.1	146.5	214.5	247.4	286.8
Q&M	54.8	123.6	161.6	197.8	223.6
Shell(3)	70.6	98.3	131.3	175.7	212.9
Sun(4)	76.8	172.0	212.4	258.0	–
TCPL(5)	84	161	244	260	303
NEB(5)	70.9	112.3	155.6	190.3	236.2
TOTAL NET SALES					
AGTL(1)	98.7	236.9	328.2	423.2	506.4
Dome	117.8	223.7	264.9	306.1	341.9
Home(2)	147	212	263	318	–
Imperial	98	178	220	260	292
IPAC(5)	125.7	210.1	261.0	322.2	361.9
Norcen – Gaz Métro					
moderate penetration	106.2	137.2	191.6	226.5	264.5
ultimate penetration	106.6	216.7	287.6	335.8	383.4
ProGas(5)	125	188	235	271	297
Q&M	91.2	228.2	318.9	411.6	493.0
Shell(3)	117.5	181.6	243.0	331.0	373.1
Sun(4)	119.4	260.8	340.3	432.1	–
TCPL(5)	121	226	365	403	462
NEB(5)	118.5	200.1	280.2	345.8	412.7

Notes: (1) Adopted Q&M gas expansion volumes.
(2) Adopted TransCanada submission to the 1978 Oil Inquiry. Exhibit 1722-9-3, Chapter IX, table P. 10 Case II.
(3) Starting year, 1982.
(4) Re-adopted Hycarb study to 1978 Oil Inquiry, tables 5 to 7.
(5) Starting year, 1981.

ESTIMATES OF TOTAL NATURAL GAS NET SALES INCLUDING GAS EXPANSION – CANADA
Comparison of Estimates
(10^{15} joules)

	1978	1980	1985	1990	2000
AGTL	1662	1807	2305	2664	3492
Dome	1572	1688	2033	2292	2862
Home Oil	1888	2099	2468	2742	3269
Imperial	1580	1693	2195	2567	3191
IPAC	1606	1765	2149	2431	3019
Norcen – moderate penetration	1637	1773	2006	2237	2647
Norcen – ultimate penetration	1637	1773	2085	2333	2765
ProGas(1)	1598	1791	2015	2290	2737
Shell(2)	1575	1812	2042	2329	2907
TransCanada(1)	1597	1762	2003	2360	2959
NEB(1)	1588	1779	2143	2442	3319

(1) Starting year of expansion, 1981.
(2) Starting year of expansion, 1982.

NEB ESTIMATES OF OIL DISPLACED AS A RESULT OF GAS PENETRATION
(Medium Cases, M^3/d)

	1985	1990	1995	2000
Quebec				
Light Fuel Oil				
No expansion case	17846	17623	17464	17162
Expansion case	15573	14000	12903	12411
Displacement	2272	3623	4561	4751
Heavy Fuel Oil				
No expansion case	19784	20627	22263	25219
Expansion case	16479	14953	15239	17003
Displacement	3305	5673	7024	8216
Atlantic				
Light Fuel Oil				
No expansion case	7946	8311	8645	8883
Expansion case	7516	7500	7548	7707
Displacement	429	810	1096	1176
Heavy Fuel Oil				
No expansion case	15732	14429	16400	19308
Expansion case	13205	16696	13228	15970
Displacement	2527	2733	2972	3337

DEMAND FOR CANADIAN GAS BY AREAS

(Petajoules/yr.)

	ALBERTA				BRITISH COLUMBIA		EAST OF ALBERTA			TOTAL CANADA		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Domestic	Export	AGTL Fuel	Reprocessing	Domestic	Export	Domestic Base Case	Domestic Expansion	Export	Domestic (1+3+4+5+7+8)	Export (2+6+9)	Total (10+11)
1979	480	544	25	186	188	320	1095	0	330	1972	1194	3166
1980	515	540	25	207	196	320	1124	0	285	2067	1146	3213
1981	536	514	26	207	207	320	1153	17	245	2144	1079	3223
1982	552	498	24	209	216	320	1176	53	245	2230	1063	3293
1983	577	449	25	210	228	320	1205	81	245	2325	1014	3339
1984	591	434	26	210	242	320	1249	108	246	2425	1000	3425
1985	612	411	27	212	256	320	1289	140	245	2536	976	3512
1986	604	302	26	239	262	320	1320	153	239	2605	860	3465
1987	615	173	25	236	266	320	1354	168	239	2663	731	3394
1988	639	157	25	232	271	320	1385	181	239	2733	716	3450
1989	649	84	26	219	277	266	1421	196	226	2788	577	3364
1990	659	84	25	218	271	116	1460	212	158	2845	358	3203
1991	670	77	23	218	279	58	1492	221	72	2903	207	3110
1992	681	48	23	227	291	0	1538	230	8	2990	56	3046
1993	709	40	24	228	304	0	1587	240	8	3091	48	3139
1994	720	0	24	228	315	0	1642	250	8	3180	8	3188
1995	734	0	25	229	329	0	1702	261	7	3280	7	3286
1996	741	0	26	231	342	0	1762	269	0	3370	0	3370
1997	750	0	27	231	356	0	1829	275	0	3468	0	3468
1998	758	0	28	231	371	0	1900	284	0	3573	0	3573
1999	767	0	29	231	388	0	1976	289	0	3680	0	3680
2000	774	0	30	232	405	0	2056	296	0	3793	0	3793
TOTAL	14331	4353	564	4870	6260	3638	32715	3920	3048	62661	11040	73701

—Figures may not add due to rounding.

—Columns 1 plus 3 represent the total domestic demand for gas in Alberta. Column 1 includes the fuel and losses for distribution of Alberta's net sales of gas. Column 3 is the fuel requirements of AGTL for all gas transported in its system leaving the province.

—Column 2 is the exports south from Alberta—Alberta and Southern and Westcoast via Kingsgate, British Columbia, and Canadian-Montana via Cardston and Aden, Alberta.

—Column 4 is the total reprocessing shrinkage from Column 5, page 2.

—Columns 5, 7 and 8 are the Canadian requirements excluding Alberta. They include fuel and losses associated with transmission and distribution outside Alberta. Column 8 is the NEB estimate of expansion markets in Quebec and the Maritimes.

—Column 6 is the Westcoast GL-41 licensed volumes.

—Column 9 is the TCPL, ICG Transmission Limited and Niagara licensed export volumes.

—Columns 2, 6 and 9, the export requirements, have been adjusted to reflect full make-up of the licensed volumes.

REPROCESSING SHRINKAGES

(Petajoules/yr.)

Year	(1) Cochrane	(2) Empress	(3) Edmonton	(4) Waterton	(5) Total (1+2+3+4)
1979	55	89	31	12	186
1980	57	110	28	12	207
1981	57	110	28	12	207
1982	56	110	32	12	209
1983	57	110	32	12	210
1984	57	110	32	12	210
1985	57	111	33	12	212
1986	57	139	33	11	239
1987	57	139	31	9	236
1988	57	139	27	8	232
1989	57	139	16	7	219
1990	57	139	17	5	218
1991	57	139	18	4	218
1992	57	139	26	4	227
1993	57	139	27	4	228
1994	57	139	28	3	228
1995	57	139	30	3	229
1996	57	139	32	3	231
1997	57	139	32	3	231
1998	57	139	33	2	231
1999	57	139	33	2	231
2000	57	139	34	2	232
TOTAL	**1250**	**2836**	**631**	**154**	**4870**

—The forecast of reprocessing shrinkages at Cochrane, Empress and Edmonton were adopted from Dome based on expected plant capacities.

—The forecast of shrinkage related to ethane extraction at Waterton was prepared by the Board.

—The Empress forecast includes expansion of 29 PJ/yr. commencing in 1986.

CANADIAN GAS DELIVERABILITY FROM CONTROLLED RESERVES

(Petajoules/yr.)

Year	(1) TCPL	(2) A&S	(3) Westcoast	(4) Westcoast GL-4	(5) Pan-Alberta	(6) Alberta Utilities Major	(7) Alberta Utilities Minor	(8) Canadian Montana	(9) Many Islands Pipelines	(10) Production East of Alberta	(11) Total
Remaining Reserves at 31 Dec. 1978	**23732**	**8771**	**7669**	**255**	**1320**	**6221**	**1340**	**344**	**671**	**1291**	**51615**
1979	1470	571	448	60	63	386	52	17	21	57	3145
1980	1455	572	472	60	64	397	44	16	21	56	3157
1981	1465	548	481	60	64	398	49	15	22	54	3154
1982	1524	541	483	60	61	399	46	13	25	53	3205
1983	1583	543	450	16	55	366	44	14	27	52	3150
1984	1477	531	417	0	50	337	43	13	31	49	2947
1985	1362	492	403	0	46	358	43	13	30	44	2791
1986	1275	457	387	0	42	328	42	14	26	47	2620
1987	1186	450	369	0	38	310	39	14	23	51	2479
1988	1149	405	341	0	36	288	34	14	20	44	2332
1989	1032	338	314	0	33	266	30	9	18	40	2080
1990	933	339	259	0	23	249	26	12	16	37	1894
1991	856	317	204	0	23	234	23	10	15	33	1715
1992	772	299	194	0	23	230	21	9	13	31	1591
1993	703	259	175	0	23	216	19	8	12	28	1443
1994	632	223	154	0	21	202	16	7	11	24	1291
1995	543	167	151	0	19	186	15	7	9	24	1121
1996	473	150	137	0	17	168	13	6	8	22	994
1997	427	141	129	0	15	152	12	5	7	21	907
1998	370	127	121	0	14	136	11	5	6	20	809
1999	321	115	113	0	12	122	9	4	6	19	722
2000	278	105	106	0	11	110	8	4	5	18	645
TOTAL	**21286**	**7690**	**6307**	**255**	**753**	**5836**	**639**	**228**	**373**	**824**	**44192**
Total Remaining Reserves at 31 Dec. 2000	**2446**	**1081**	**1362**	**0**	**567**	**385**	**701**	**116**	**298**	**467**	**7423**

—NEB forecasts of production from contracted reserves for TCPL, A&S, Westcoast and Pan-Alberta are in Columns 1, 2, 3 and 5 respectively.
—The Westcoast forecast includes all gas in the Westcoast supply area (excepting supply for Licence GL-4).
—Westcoast GL-4 is at the annual authorized level until total licensed volumes have been produced.
—Major and Minor Alberta utilities supply forecasts were adopted from the Polar Gas submission.
—Canadian-Montana's supply forecast was adopted from its submission.
—Many Islands Pipelines' forecast was adopted from the SPC submission.
—Production East of Alberta includes the forecast of Saskatchewan production from the SPC submission and the Board's forecast of Ontario production.
—Remaining reserves as at 31 December 1978 have been allocated on the basis of available information regarding controlled supplies.

GAS SUPPLY AVAILABLE TO MEET ALBERTA DEMAND

(Petajoules/yr.)

Year	(1) Total Demand	(2) Alberta Supplies	(3) TCPL Alberta Supplies	(4) Deferred Supply	(5) Shallow Uncommitted Supply	(6) Non-Associated Uncommitted Supply	(7) Supply from B.E.R. Reserves	(8) Alberta Trend Supply	(9) Total (2+3+4+5+6+7+8)	(10) Surplus (9 − 1)
1979	1234	1079	147	0	40	42	2	0	1310	76
1980	1287	1084	147	0	93	101	4	15	1443	157
1981	1282	1062	150	0	130	160	7	44	1553	271
1982	1283	1044	153	0	143	224	9	95	1668	385
1983	1261	963	157	14	148	274	11	161	1728	467
1984	1260	896	163	16	142	312	13	236	1780	520
1985	1262	883	166	35	131	342	15	311	1882	620
1986	1172	805	169	39	123	367	18	378	1899	727
1987	1048	771	170	36	115	384	20	439	1935	886
1988	1053	697	168	32	110	397	22	497	1922	869
1989	978	596	158	28	102	405	24	553	1866	889
1990	986	611	149	25	95	400	26	606	1913	927
1991	988	570	144	24	89	390	28	654	1899	911
1992	979	545	138	23	84	375	30	693	1888	909
1993	1000	487	132	37	80	353	32	722	1843	843
1994	972	433	127	36	72	329	33	744	1774	801
1995	988	358	118	36	66	305	35	759	1678	690
1996	998	320	112	34	63	279	36	771	1616	618
1997	1008	293	107	57	61	255	37	778	1590	582
1998	1017	261	102	87	55	232	38	781	1556	539
1999	1027	234	98	86	51	212	39	781	1501	474
2000	1036	210	94	84	45	202	40	778	1454	418
TOTAL	**24119**	**14204**	**3067**	**730**	**2039**	**6341**	**522**	**10797**	**37699**	**13580**

—Column 1 is the total Alberta demand including exports south from Alberta and is the sum of Columns 1 to 4 on page 1.
—Column 2 is the sum of the major and minor Alberta utilities forecast, the A&S forecast less A&S Columbia sales and Pan-Alberta contracted sales, the Westcoast GL-4 forecast and the Canadian-Montana forecast.
—Column 3 is the Board's estimate of TCPL's Alberta sales and the AGTL fuel and reprocessing shrinkages associated with TCPL's supply (Columns 3 and 4, page 6).
—Column 4 is the Board's estimate of supply from deferred reserves in Alberta
—Column 5 is the Board's estimate of supply from uncommitted shallow gas reserves in N.W. and S.E. Alberta
—Column 6 is the Board's estimate of supply from the remaining uncommitted gas reserves in Alberta.
—Column 7 is the Board's estimate of supply from ½ of the reserves beyond economic reach in Alberta.
—Column 8 is the Board's forecast of deliverability from Alberta trend gas additions.
—Column 10 is the volume of gas supply in excess of Alberta's total requirements.

ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND

(Petajoules/yr.)

Year	(1) Total Demand	(2) Westcoast Supply	(3) Pan-Alberta Supply	(4) A&S (Columbia) Sales	(5) B.C. Trend Supply	(6) Net B.C. Supply (2+3+4+5)	(7) Demand for Alberta Gas (1−6)
1979	507	448	41	5	0	494	13
1980	517	472	41	5	3	522	−5
1981	526	481	41	6	8	537	−10
1982	536	483	41	11	16	550	−14
1983	547	450	41	11	30	532	16
1984	562	417	41	14	50	522	40
1985	576	403	31	14	70	517	59
1986	581	387	41	14	89	531	50
1987	585	369	41	14	110	533	52
1988	592	341	41	14	130	526	66
1989	544	314	41	15	149	519	25
1990	387	259	0	15	166	439	−52
1991	337	204	0	15	181	400	−63
1992	291	194	0	15	196	404	−113
1993	304	175	0	16	209	400	−96
1994	315	154	0	16	220	390	−75
1995	329	151	0	16	229	395	−66
1996	342	137	0	16	234	387	−45
1997	356	129	0	16	237	382	−25
1998	371	121	0	17	237	375	−3
1999	388	113	0	17	234	364	24
2000	405	106	0	17	230	353	52
TOTAL	9898	6307	442	295	3027	10071	−173

—Column 1 is the total British Columbia demand obtained by adding the total domestic and export demands, Columns 5 and 6 from page 1.
—Column 2 is the NEB forecast of Westcoast gas supply from Column 3, page 3.
—Column 3 is the Pan-Alberta firm contract with Westcoast. In 1985, the Pan-Alberta supplies including supplies available from A&S less Pan-Alberta's commitments east of Alberta are deficient overall.
—Column 4 is A&S's estimate of its sales to Columbia Natural Gas in British Columbia.
—Column 5 is the NEB forecast of supply from trend additions in British Columbia.
—Column 7 is the additional gas supply necessary to meet British Columbia total demand.

ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA

(Petajoules/yr.)

Year	(1) Total Demand	(2) TCPL Supply	(3) TCPL Alberta Sales	(4) AGTL Fuel and Reprocessing	(5) Many Islands Pipelines Supply	(6) Pan-Alberta Supply	(7) Production East of Alberta	(8) Saskatchewan Trend Supply	(9) Net East of Alberta Supply (2−3−4+5 +6+7+8)	(10) Demand for Alberta Gas (1−9)
1979	1425	1470	20	127	21	23	57	0	1425	0
1980	1410	1455	20	127	21	23	56	1	1410	0
1981	1415	1465	23	127	22	23	54	1	1415	0
1982	1474	1524	26	127	25	23	53	2	1474	0
1983	1531	1583	31	127	27	23	52	3	1531	0
1984	1603	1477	37	127	31	23	49	4	1420	183
1985	1674	1362	39	127	30	23	44	5	1299	375
1986	1712	1275	42	127	26	23	47	6	1209	503
1987	1760	1186	45	124	23	23	51	9	1123	637
1988	1805	1149	47	120	20	23	44	12	1081	724
1989	1843	1032	51	107	18	23	40	15	970	873
1990	1830	933	53	96	16	23	37	17	877	953
1991	1785	856	56	88	15	23	33	19	802	983
1992	1776	772	59	79	13	23	31	21	722	1054
1993	1835	703	61	71	12	23	28	23	657	1178
1994	1900	632	64	63	11	21	24	25	586	1314
1995	1969	543	65	53	9	19	24	26	504	1465
1996	2030	473	66	45	8	17	22	28	437	1593
1997	2104	427	67	40	7	15	21	31	393	1711
1998	2184	370	69	34	6	14	20	32	340	1845
1999	2265	321	70	28	6	12	19	34	294	1971
2000	2352	278	71	23	5	11	18	36	254	2098
TOTAL	**39683**	**21286**	**1083**	**1984**	**373**	**456**	**824**	**351**	**20223**	**19460**

—Column 1 is the total demand for gas East of Alberta from Columns 7, 8 and 9, page 1
—Column 2 is the NEB forecast of supply from TCPL's contracted gas volumes (Column 1, page 3).
—Column 3 is the Board's estimate of TCPL's sales to Alberta utilities
—Column 4 is the NEB estimate of total Empress shrinkage and the AGTL fuel required to transport gas for East of Alberta use. The volumes are based on TCPL throughput.
—Column 5 is the Many Islands Pipelines' forecast of production from Column 9, page 3.
—Column 6 is the projected supply of Pan-Alberta to meet its East of Alberta commitments.
—Column 7 is the forecast of production East of Alberta (Column 10, page 3).
—Column 8 is the NEB forecast of supply from trend additions in Saskatchewan
—Column 10 is the additional gas supply necessary to meet total demand East of Alberta

ALLOCATION OF GAS SURPLUS TO ALBERTA DEMAND

(Petajoules/yr.)

	SURPLUS SUPPLIES			DEMAND FOR ALBERTA SURPLUS		ALLOCATION OF SURPLUS		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Alberta Surplus	Supply from Temporary Surplus	Total	East of Alberta	British Columbia	East of Alberta	British Columbia	Temporary Surplus Available for later use
1979	76	0	76	0	13	0	13	63
1980	157	0	162	0	−5	0	0	162
1981	271	0	281	0	−10	0	0	281
1982	385	0	399	0	−14	0	0	399
1983	467	0	467	0	16	0	16	451
1984	520	0	520	183	40	183	40	296
1985	620	0	620	375	59	375	59	186
1986	727	0	727	503	50	503	50	175
1987	886	0	886	637	52	637	52	197
1988	869	0	869	724	66	724	66	79
1989	889	9	897	873	25	873	25	0
1990	927	0	979	953	−52	953	0	26
1991	911	10	983	983	−63	983	0	0
1992	909	32	1054	1054	−113	1054	0	0
1993	843	116	1055	1178	−96	1055	0	0
1994	801	116	992	1314	−75	992	0	0
1995	690	116	872	1465	−66	872	0	0
1996	618	116	779	1593	−45	779	0	0
1997	582	116	723	1711	−25	723	0	0
1998	539	116	659	1845	−3	659	0	0
1999	474	116	590	1971	24	583	7	0
2000	418	116	534	2098	52	521	13	0
TOTAL	13580	977	15126	19460	−173	12470	341	2316

—Column 1 is the total projected supply of gas surplus to Alberta's requirements from Column 10, page 4.

—Additional gas was assumed to flow to meet British Columbia deficiencies when required.

—After supplying British Columbia and East of Alberta as shown in Columns 6 and 7, there remain volumes of gas which provide a temporary overall surplus to Canadian Demand. These volumes, shown in Column 8, are assumed not to be produced and are converted to a forecast of deliverability starting in 1989 as shown in Column 2. The temporary surplus in British Columbia is also included in Columns 2 and 3 and is assumed to be available East of Alberta if required.

—The total surplus supply, Column 3, is allocated between British Columbia and East of Alberta based upon the proportion of the unsatisfied demand which is attributable to each of these regions.

ADJUSTMENTS TO ALBERTA UNCOMMITTED AND TREND SUPPLIES

(Petajoules/yr.)

			UNADJUSTED		ADJUSTED	
	(1)	(2)	(3)	(4)	(5)	(6)
Year	Temporary Surplus Supply	Deferred Deliverability	Alberta Uncommitted	Alberta Trend	Alberta Uncommitted	Alberta Trend
1979	63	0	84	0	22	0
1980	162	0	198	15	51	0
1981	281	0	297	44	59	0
1982	399	0	376	95	71	0
1983	451	0	433	161	143	0
1984	296	0	468	236	408	0
1985	186	0	488	311	488	125
1986	175	0	508	378	508	203
1987	197	0	519	439	519	242
1988	79	0	528	497	528	418
1989	0	9	532	553	532	561
1990	26	0	521	606	521	580
1991	0	10	507	654	507	664
1992	0	32	490	693	490	725
1993	0	116	465	722	465	838
1994	0	116	434	744	434	859
1995	0	116	406	759	406	875
1996	0	116	379	771	379	887
1997	0	116	354	778	354	894
1998	0	116	325	781	325	897
1999	0	116	302	781	302	897
2000	0	116	288	778	288	894
TOTAL	2316	977	8902	10797	7801	10560

—Column 1 is the temporary surplus Alberta supply taken from Column 8, page 7.

—Column 2 is the deliverability, commencing in 1989, attributable to the volumes indicated to be surplus in Column 1 and assumed not to be produced in the period indicated in Column 1.

—The figures in Columns 1 and 2 were used to adjust the NEB forecasts of supply from uncommitted and trend gas in Alberta.

—The Board judged that the bulk of the adjustments necessary would be made to the trend gas forecast, Column 4, which is taken from Column 8, page 4. Any further adjustment was made to the uncommitted supply forecast, Column 3, which is the sum of Columns 5, 6 and 7 from page 4.

—The adjusted forecasts to be used in the total supply-demand balance are in Columns 5 and 6

BRITISH COLUMBIA SUPPLY-DEMAND BALANCE

(Petajoules/yr.)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	British Columbia Demand	Huntingdon Export	Total (1+2)	British Columbia Net Supply	Alberta Surplus to British Columbia	Total (4+5)	Deficiency (3−6)
1979	188	320	507	494	13	507	0
1980	196	320	517	522	−5	517	0
1981	207	320	526	537	−10	526	0
1982	216	320	536	550	−14	536	0
1983	228	320	547	532	16	547	0
1984	242	320	562	522	40	562	0
1985	256	320	576	517	59	576	0
1986	262	320	581	531	50	581	0
1987	266	320	585	533	52	585	0
1988	271	320	592	526	66	592	0
1989	277	266	544	519	25	544	0
1990	271	116	387	439	−52	387	0
1991	279	58	337	400	−63	337	0
1992	291	0	291	404	−113	291	0
1993	304	0	304	400	−96	304	0
1994	315	0	315	390	−75	315	0
1995	329	0	329	395	−66	329	0
1996	342	0	342	387	−45	342	0
1997	356	0	356	382	−25	356	0
1998	371	0	371	375	−3	371	0
1999	388	0	388	364	7	371	17
2000	405	0	405	353	13	366	39
TOTAL	6260	3638	9898	10071	−229	9842	56

—Column 1 is taken from Column 5, page 1.
—Column 2 is taken from Column 6, page 1.
—Column 4 is taken from Column 6, page 5.
—Column 5 is taken from Column 7, page 7, including British Columbia surplus supplies from Column 5, page 7, which were assumed to be available for markets East of Alberta.

EAST OF ALBERTA SUPPLY-DEMAND BALANCE

(Petajoules/yr.)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	Canadian	Export	Total (1+2)	Net Supply East of Alberta	Surplus to East of Alberta	Total (4+5)	Deficiency (3−6)
1979	1095	330	1425	1425	0	1425	0
1980	1124	285	1410	1410	0	1410	0
1981	1170	245	1415	1415	0	1415	0
1982	1229	245	1474	1474	0	1474	0
1983	1286	245	1531	1531	0	1531	0
1984	1357	246	1603	1420	183	1603	0
1985	1429	245	1674	1299	375	1674	0
1986	1473	239	1712	1209	503	1712	0
1987	1522	239	1760	1123	637	1760	0
1988	1566	239	1805	1081	724	1805	0
1989	1617	226	1843	970	873	1843	0
1990	1672	158	1830	877	953	1830	0
1991	1713	72	1785	802	983	1785	0
1992	1768	8	1776	722	1054	1776	0
1993	1827	8	1835	657	1055	1712	123
1994	1892	8	1900	586	992	1587	322
1995	1963	7	1969	504	872	1376	593
1996	2030	0	2030	437	779	1217	813
1997	2104	0	2104	393	723	1116	988
1998	2184	0	2184	340	659	998	1186
1999	2265	0	2265	294	583	877	1388
2000	2352	0	2352	254	521	775	1577
TOTAL	36635	3048	39683	20223	12470	32693	6990

—Column 1 is taken from Columns 7 and 8, page 1.
—Column 2 is taken from Column 9, page 1.
—Column 4 is taken from Column 9, page 6.
—Column 5 is taken from Column 6, page 7.

TOTAL CANADIAN SUPPLY-DEMAND BALANCE

(Petajoules/yr.)

	DEMAND			SUPPLY					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Domestic	Export	Total (1+2)	Total Controlled	Alberta Uncommitted	Alberta Deferred	Trend Supply	Total (4+5+6+7)	Deficiency (3−8)
Remaining Reserves at 31 December 1978				**51615**	**13645**	**4450**	**0**	**69710**	
Total Including Trend to 31 December 2000							**35541**	**105251**	
1979	1972	1194	3166	3145	22	0	0	3167	0
1980	2067	1146	3213	3157	51	0	4	3213	0
1981	2144	1079	3223	3154	59	0	9	3223	0
1982	2230	1063	3293	3205	71	0	18	3294	0
1983	2325	1014	3339	3150	143	14	33	3339	0
1984	2425	1000	3425	2947	408	16	54	3425	0
1985	2536	976	3512	2791	488	35	200	3513	0
1986	2605	860	3465	2620	508	39	298	3465	0
1987	2663	731	3394	2479	519	36	361	3395	0
1988	2733	716	3450	2332	528	32	559	3451	0
1989	2788	577	3364	2080	532	28	725	3364	0
1990	2845	358	3203	1894	521	25	763	3203	0
1991	2903	207	3110	1715	507	24	864	3110	0
1992	2990	56	3046	1591	490	23	942	3046	0
1993	3091	48	3139	1443	465	37	1070	3016	123
1994	3180	8	3188	1291	434	36	1105	2866	322
1995	3280	7	3286	1121	406	36	1130	2693	593
1996	3370	0	3370	994	379	34	1149	2557	813
1997	3468	0	3468	907	354	57	1162	2480	988
1998	3573	0	3573	809	325	87	1166	2387	1186
1999	3680	0	3680	722	302	86	1165	2275	1405
2000	3793	0	3793	645	288	84	1160	2177	1616
TOTAL	**62661**	**11040**	**73701**	**44192**	**7801**	**730**	**13937**	**66659**	**7041**
Remaining Reserves at 31 December 2000				**7423**	**5844**	**3720**	**21604**	**38592**	

—Figures may not balance due to rounding.
—Board estimates of the remaining marketable gas reserves at 31 December, 1978 which support the NEB forecasts of supply are shown at the top of Columns 4 to 8. Column 5 includes all of the 1978 Alberta reserves addition.
—The total trend additions from 1 January, 1979 to 31 December 2000 are 35.5 EJ and support the total deliverability from trend gas in Column 7.
—Columns 1 to 6 inclusive are taken from Columns 10, 11 and 12, page 1; Column 11, page 3; Column 5, page 8 and Column 4, page 4 respectively.
—Column 7 is the sum of Columns 5, page 5; Column 8, page 6 and Column 6, page 8.
—The total deficiency in Column 9 includes deficiencies in British Columbia and East of Alberta as shown in Column 7, page 9 and Column 7, page 10 respectively.

NATURAL GAS EXPORTS BY AREA FOR EXISTING LICENCES

(Petajoules/yr.)

		Licence Number	Total Remaining	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
				Annual																
SOUTH FROM ALBERTA	A&S	GL-3*	1313.2	180.5	177.5	165.2	165.2	165.2	165.2	165.2	129.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-16*	823.8	89.0	89.3	89.0	82.2	80.7	80.7	80.7	80.7	80.7	71.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-24*	1192.6	92.8	93.1	86.4	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	76.8	48.1	39.7	0.0	0.0
		GL-35*	511.0	80.6	79.5	72.8	72.8	72.8	72.8	59.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CMPL	GL-5*	90.8	16.7	16.7	16.7	12.9	11.3	11.3	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-17*	79.4	10.5	10.0	10.0	7.9	7.9	7.9	7.9	7.9	7.9	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-25*	58.6	9.4	9.5	9.4	9.3	7.9	7.9	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-36*	29.1	4.7	4.7	4.6	3.9	3.9	3.9	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WTCL	GL-4*	176.0	59.8	60.0	56.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WTCL	Makeup**	78.9	0.0	0.0	3.6	59.8	15.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TOTAL		4353.2	544.1	540.3	513.9	498.0	449.0	433.6	411.1	301.7	172.5	156.6	84.0	84.0	76.8	48.1	39.7	0.0	0.0
BRITISH COLUMBIA	WTCL	GL-41*	3464.7	319.6	320.5	319.6	319.6	319.6	320.5	319.6	319.6	319.6	320.5	266.2	0.0	0.0	0.0	0.0	0.0	0.0
	WTCL	Makeup**	173.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.8	57.9	0.0	0.0	0.0	0.0
	TOTAL		3638.4	319.6	320.5	319.6	319.6	319.6	320.5	319.6	319.6	319.6	320.5	266.2	115.8	57.9	0.0	0.0	0.0	0.0
EAST OF ALBERTA	ICG	GL-28*	6.2	1.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.0
		GL-29*	140.7	12.4	9.3	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.6
	NGT	GL-6	47.2	6.8	6.8	6.8	6.8	6.8	6.8	6.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	TCPL	GL-1	116.0	77.7	38.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		GL-18*	622.4	57.8	57.5	57.4	57.4	57.4	57.5	57.4	57.4	57.4	57.5	47.8	0.0	0.0	0.0	0.0	0.0	0.0
		GL-19	71.9	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	4.2	0.0	0.0	0.0	0.0	0.0	0.0
		GL-20*	458.9	36.0	35.8	35.7	35.7	35.7	35.8	35.7	35.7	35.7	35.8	35.7	35.7	29.7	0.0	0.0	0.0	0.0
		GL-37	881.5	75.0	74.6	74.4	74.4	74.4	74.6	74.4	74.4	74.4	74.6	74.4	62.0	0.0	0.0	0.0	0.0	0.0
		GL-38	225.1	19.2	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	15.8	0.0	0.0	0.0	0.0	0.0
		GL-39	32.4	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.3	0.0	0.0	0.0	0.0	0.0
		GL-43	230.2	17.8	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	0.0	0.0	0.0	0.0
	TCPL	Makeup**	215.5	16.7	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	0.0	0.0	0.0	0.0
	TOTAL		3048.0	330.0	285.5	245.4	245.4	245.4	245.9	245.2	238.6	238.6	239.1	226.4	158.4	72.4	8.4	8.4	8.3	6.6
CANADA	**TOTAL**		11039.5	1193.7	1146.3	1078.8	1063.0	1014.0	999.9	975.8	859.9	730.7	716.2	576.6	358.2	207.1	56.5	48.1	8.3	6.6

* Including maximum annual makeup of volumes not taken in prior years, as permitted by existing annual averaging conditions in the licence.
** Assuming that the licences will be conditioned to permit the makeup of volumes not taken in prior years.
— In the case of Westcoast, makeup volumes are assumed to be exported at the end of the licence term.
— In the case of TransCanada, makeup volumes are assumed to be averaged over the licence term.

Abbreviations

TCPL — TransCanada
A&S — Alberta & Southern
NGT — Niagara
CMPL — Canadian-Montana
WTCL — Westcoast
ICG — ICG Transmission Ltd.